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AIR POLLUTION FROM FUEL COMBUSTION IN STATIONARY SOURCES

PROCESSES RESEARCH, INC.

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AIR POLLUTION FROM FUEL COMBUSTION
IN STATIONARY SOURCES

FINAL REPORT
ON THE
U. S. NATIONAL REPORT TO THE O.E.C.D.
JOINT GROUP ON AIR POLLUTION FROM FUEL COMBUSTION
IN STATIONARY SOURCES

Task Order No. 19

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Prepared for
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Research Triangle Park, North Carolina

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Industrial Planning and Research
Cincinnati, Ohio

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ABSTRACT

This report documents the preparation of the U. S. National Report to the Organization for Economic Cooperation and Development - Joint Group on Air Pollution from Fuel Combustion in Stationary Sources. The report contains estimates of past (1960 and 1970) and future (1980) fuel consumption in stationary combustion sources and associated quantities of the air pollutants - sulfur oxides, nitrogen oxides, and particulate - emitted to the atmosphere from the combustion of these fuels. ^{are estimated} Abatement strategies to control the 1980 level of pollutant emissions to the alternative target levels, as obtained in 1960 and 1970 cases, were formulated and impressed on the 1980 situation.

The study found that the projected emissions of sulfur and nitrogen oxides could be expected to approximately double the 1968 levels of pollution without implementation of new controls. Those of particulate emissions would be expected to increase ~~some~~ tenfold without continuing the application of best control practice.

The 1980 emissions can be controlled to the targeted levels through implementation of control and fuels management practices. The estimated costs for achieving control are appreciable, approaching a total estimated capital expenditure of about \$13 billion (cumulative through 1980) and an annual operating cost climbing to \$2.8 billion in 1980 (1970 dollar estimates).

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FOREWORD

This report is the final documentation covering the preparation of the U. S. National Report to the Joint Group on Air Pollution from Fuel Combustion in Stationary Sources. The Joint Group is an ad hoc committee of the Organization for Economic Cooperation and Development (of which the United States is a member) constituted to study and report on possible approaches and estimated costs for the control of such air pollution by 1980 in the various member countries.

The U. S. National Report as submitted to the O.E.C.D. is presented in Section IV. It was prepared to meet the requirements for submission to the O.E.C.D. and should not be taken as an "official policy" document, particularly with respect to the assumptions related to control strategy, which were in some cases arbitrary or dictated by the study format. At the time this report was prepared, the best available cost data (in 1969-1970) were used. In retrospect from the time of completion and issuance, it is noted that better cost data, especially in regard to costs for fine gas scrubbing, are now available. For this reason it is recommended that the cost data contained in this report be used only after careful consideration of its appropriateness and state of development.

The results presented in the report are considered valid for their intended purpose, but should not be construed as an attempt either to forecast the means by which air pollution will be controlled in 1980, or to predict the level of control which will be attained by that time through the implementation of officially adopted strategies.

The study scope and the methodology for preparing the report are presented in Section I with a brief identification of the more important factors and assumptions governing the preparation of the estimates. A discussion of the results is found in Section II with the conclusions drawn presented in Section III.

While the present study was quite modest in scope and effort, some aspects of the investigation were conducted in greater depth than for previous studies. In addition, tailoring the approach to meet the needs of the O.E.C.D. study format required some modifications to previously exercised approaches. Consequently, some new insights were gained into the nature of the problem of air pollution from fuel combustion. These are discussed in Section II as "Issues Arising From the Study."

During the compilation of the various national reports into the O.E.C.D. report, certain questions were raised concerning the U. S. National Report. These questions dealt with the U. S. strategy for sulfur oxides abatement, costs for oil desulfurization, and electrostatic precipitator costs. These

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items were re-examined, and more detailed explanations of their derivations were prepared for the O.E.C.D. These derivations are included in this report as Appendices I through III, respectively.

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SECTION I - SCOPE AND METHODOLOGY

The object of the study was to develop an estimate of the nature of the abatement strategies and costs of their implementation to achieve control to a predetermined quantity of emission on a national scale for the three major pollutants from fuel combustion: particulate, sulfur oxides, and nitrogen oxides. The U.S. report presents the situations for control of the 1980 emissions to the levels existing in 1970 and 1960. Briefly these steps were taken to arrive at the estimates presented in the report (Section IV):

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- (a) using historical data, develop a picture of the fuel quantities and fuel qualities employed in the various consuming sectors.
 - (b) using historical data for emissions after application of control equipment, develop emission factors appropriate to the degree of control practiced in the target years.
 - (c) calculate estimates for the total national emissions of the three pollutants by fuel type and consuming sector for 1960 and 1970.
 - (d) using the historical data developed previously for fuel consumption and information relating to normal practice in the various sectors, develop predictions of the fuel utilization patterns for 1980.
 - (e) using the most current data for emissions resulting after application of best control practice, develop emission factors by fuel type and consuming sector.
 - (f) estimate the quantity of emissions likely to exist on the national level on the basis of the projected fuel utilization patterns and the degree of control likely to be practiced if no special steps to abate air pollution are implemented.
 - (g) formulate an abatement strategy to accomplish emission control to the two chosen target levels.
 - (h) calculate the costs of implementation of these control strategies based on both total capital costs from present through 1980 and the 1980 annual operating costs.

Planning of the control strategy was predicated on numerous simplifying assumptions. These related to matters such as which control methods would be used, the rate at which different control methods could be introduced, etc. The assumptions were not intended to be a prediction of things to come, but an attempt was made to relate them to what appears, from the information available, to be a reasonable approach. They were intended to provide a rational basis for calculating estimated costs for the specified levels of control.

Of the three pollutants considered, sulfur oxides present the most difficult control problem - hence the primary thrust of the strategy was control of sulfur oxides. First a strategy was developed to produce the two levels of sulfur oxide control to be used as a basis for subsequent calculation of costs, i.e., control to

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1960 levels of emission in 1980 and control to 1970 levels of emission in 1980. Any incidental benefits in NO_x and particulate control produced by the control application assumed for sulfur oxide control were factored into subsidiary supplemental strategies assumed for NO_x and particulate control, e.g., some NO_x control was assumed to result incidentally from scrubbing of flue gas for sulfur oxide removal. The additional reduction required to give the levels of control of NO_x for 1980 was assumed to come from application of techniques for modification of combustion systems.

It was further assumed that no single control method could be considered as a total solution for sulfur control over the next ten years. Sulfur reductions from power stations were assumed to come from increased mining of low sulfur coal, increased use of mechanically cleaned coal, application of flue gas cleaning systems, and increased use of desulfurization to produce low sulfur residual fuels. Slight increases for power station consumption of natural gas were assumed, but demand from other industries where control techniques for sulfur and nitrogen oxides are uneconomical was assumed to cause most of the projected increase in natural gas production to go to the "Other Industries" sector. Control in the third major sector, "Domestic and Commercial," was assumed to come from increased use of low sulfur oil.

Consideration of this methodology reveals certain important limitations one must consider in discussion or in drawing conclusions based on the data presented here or in using the data for other purposes. First, there is the matter of the abatement strategy. At the time the basic work for this report was undertaken, ambient air quality standards either had not been formulated or implemented in most of the participating nations. Also the U. S. had not yet set the standards of performance for new sources. For this reason the "roll-back" procedure was utilized to determine the amount of emission reduction required in 1980. The control strategy which seemed plausible from the state-of-the-technology and at the same time satisfied the study format was developed.

The strategy thus developed contains certain simplifying assumptions, the implications of which are discussed in detail in Section III. However, the most important implication is that it is not necessary to control all pollution sources to achieve the targeted emission level. This situation arises primarily because the targeted level is based on a national emission inventory and not ambient air quality.

The second critical aspect is the method used in arriving at the estimated fuel demands for the various consuming sectors in 1980. The estimates were made by assuming continued prevalence of the present trend of fuel consumption existing in 1970 where special steps for air pollution abatement had not been taken. In certain areas of the country steps have already been taken to abate air pollution by substitution of clean fuels for coal. The trends established in these areas are discounted for the purposes of the 1980 base case so that the abatement strategy

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and costs formulated for the report would be independent of localized practices and reflect only the results of the formulated strategies. No attempt was made to establish an estimate of fuels availabilities as this was beyond the scope of the study.

SECTION II - RESULTS AND DISCUSSION

During the next decade energy demand will continue overwhelmingly to be met by the use of fossil fuels. Based on established utilization trends, natural gas and coal will account for an estimated 82 percent of the stationary combustion source energy requirements in 1980, with gaseous fuels contributing 53 percent and coal 29 percent of the total. The demand for liquid fuels for stationary combustion sources will also increase from a 1968 level of 189 million tons to 337 million tons in 1980. While the absolute amounts of fuels required by the various sectors will increase, the relative distributions will change. These changes in the pattern of fuel consumption by sector, and within sectors, may somewhat influence abatement policies. Fuel demand for power stations and industry will increase considerably more than for domestic and commercial uses. These latter uses which represented 27 percent of the total demand in 1968 will drop to 17 percent in 1980. On the basis of the estimates for energy demand and those abatement procedures practiced nationally (i.e. reference date 1968), the projected emissions of sulfur and nitrogen oxides are expected to approximately double during the period 1968 to 1980. This increase in energy demand coupled with the technology and fuels available for satisfying this demand dictates that abatement of air pollution arising from the combustion of fossil fuels will be needed to prevent the further deterioration of the environment.

From the standpoint of pollution from combustion, sulfur oxides from the combustion of coal have been recognized as of dominant importance in the present and projected picture; and the coal burning power stations are by far the most important single source of pollution. This is illustrated by Figure 1 which shows types of fuels used in each consuming sector in 1968. Power station coal greatly exceeds all other fuel use categories except for natural gas and oil, largely distillate fuels, used in the domestic and commercial sector, and these latter categories are "clean" fuels which produce relatively small amounts of pollution. Because of the dominant importance of coal as a fuel and power stations as a user, primary consideration was given to ways that projected electrical requirements might be met without exceeding the pollutant emission limits prescribed by the study guidelines. Even after control, it is estimated that total coal combustion will account for 83 percent of the total sulfur oxides pollution, with power station coal combustion contributing 74 percent of the total.

The 1980 fuel use patterns which would result from applying the assumed control methods is shown in Figure 2 where data are presented on the same basis as Figure 1 to permit direct comparisons by fuel type and fuel use category to 1968 consumption. The results of the assumed control strategy on sulfur balance are shown by Figure 3 where sulfur emissions by fuel type and use category are represented by blocks in the top half of the figure and sulfur which is not emitted as a result of the assumed use of control methods are represented by the blocks in

FIGURE I
1968 FOSSIL FUEL SITUATION
DISTRIBUTION & CONSUMPTION BY SECTOR

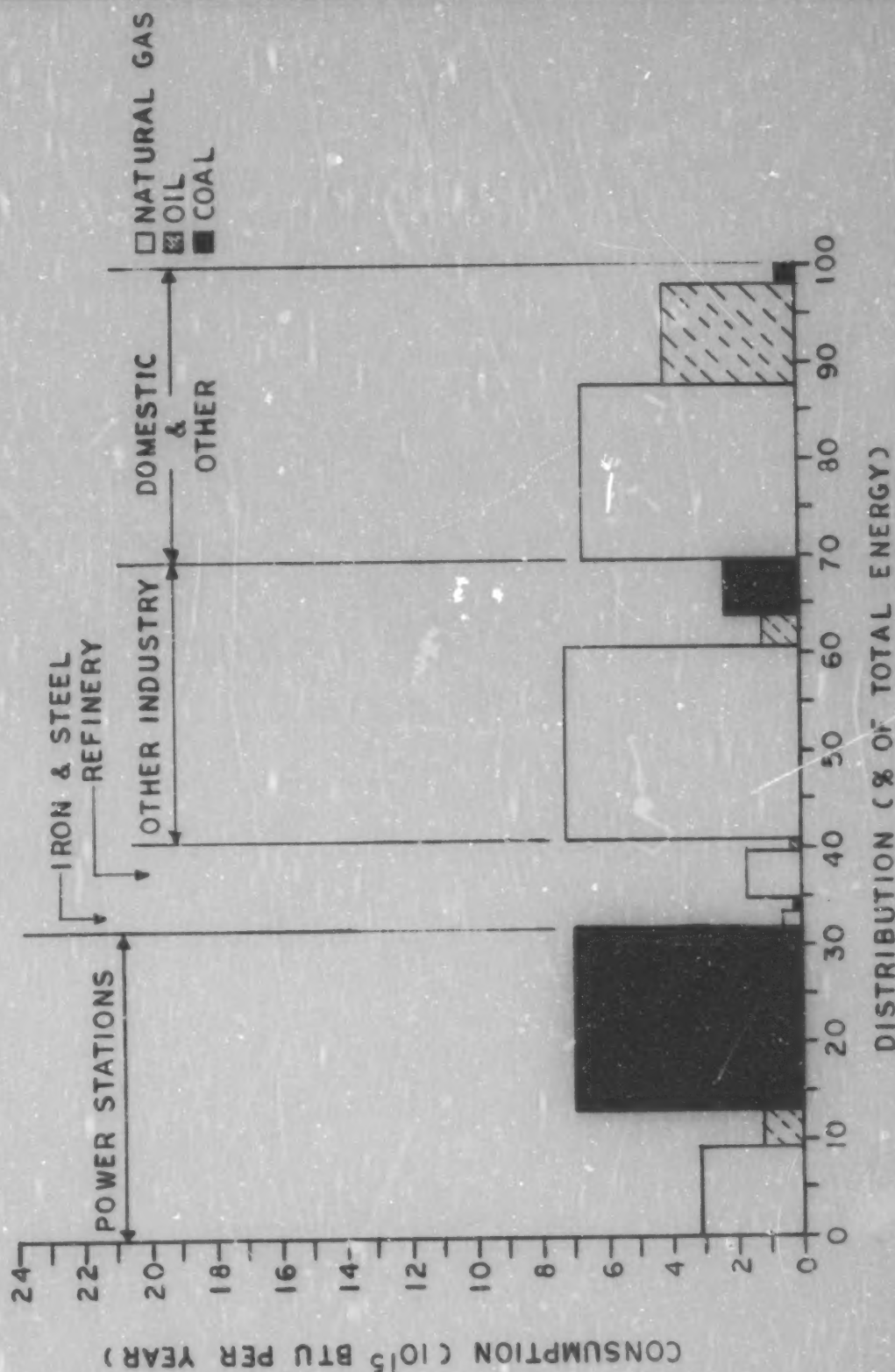
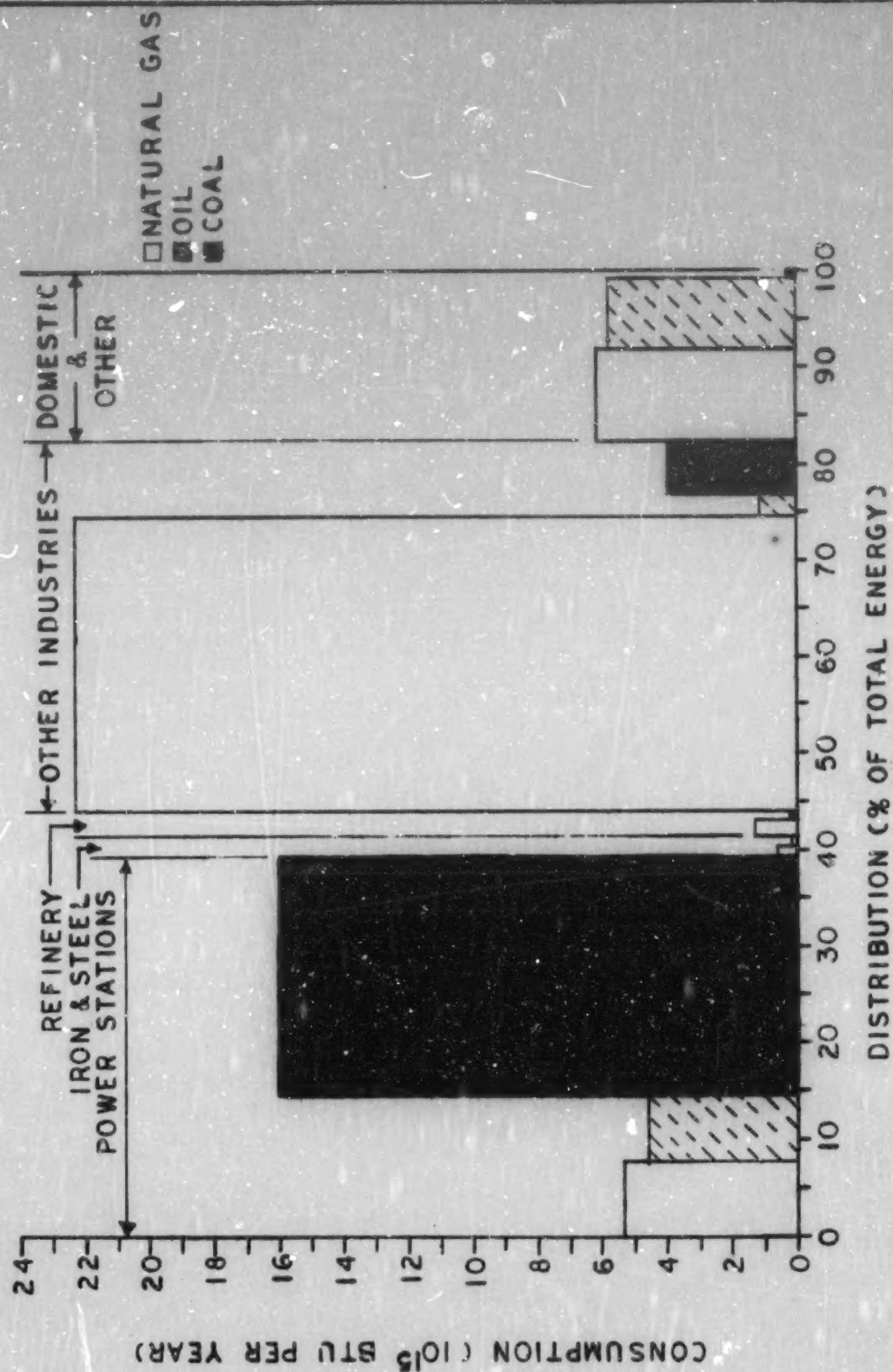


FIGURE 2
1980 FOSSIL FUEL SITUATION
DISTRIBUTION & CONSUMPTION BY SECTOR



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the lower half of the figure. The irregular line for emissions associated with oil and natural gas is intended to represent the unknown quantity of emissions which results from flaring of waste gases in gas fields and refineries. Emissions in this category were, because of lack of data, omitted from the study. This problem is discussed with other issues arising from the study under Section II.B which follows; it is important, however, to recognize at this point that the sulfur balance represented by Figure 3 would, if data were available, have some incremental amounts of sulfur distributed in the fuel oil and natural gas categories.

The strategies for nitrogen oxides emission control and particulate emission control involve application of combustion process modification to supplement NOx control achieved incidental to SOx control and application of electrostatic precipitators as necessary to give particulate emission reductions beyond those assumed to result from coal cleaning and application of flue gas cleaning to power station emissions. The results of the application of the assumed control strategy on emission levels for NOx and particulate are shown in Figures 4 and 5.

Control of the sulfur oxides situation in 1980 will depend principally on the development and implementation of flue gas cleaning and coal cleaning processes in addition to the requirement for natural gas and natural low sulfur coal mining. The present prospects for control of nitrogen oxides depend on the development and implementation of improved combustion technology. There is some evidence that this technology is now becoming available for gaseous and liquid fuels. The technology for control of particulate emissions is available now, although there is some disagreement on the efficiency of control which can be realized with the existing practices. Naturally occurring low sulfur fuels will be in great demand by all industrialized countries and available in short supply. Substitution of low sulfur fuels derived from natural supplies cannot alone alleviate the sulfur emission problem.

The prospects for meeting the targeted control levels are keyed to fuel supply and implementation of control technology. Adequate reserve capacities for the required fuels at the quality levels called for by the abatement strategy must be available to meet consumer demands. The control technologies for the pollutants must be developed, demonstrated, and utilized in sufficient magnitude before 1980 to have a meaningful impact on the future situation. These include, in various phases of development, oil desulfurization processes, flue gas desulfurization processes, coal cleaning, nitrogen oxides combustion control techniques, and advanced particulate control equipment. The projected requirement for desulfurized heavy oil is about 1.2 billion (10^9) barrels for 1980. This indicates a need for some 150 new, hydrogen treating plants integrated with major petroleum refining complexes of some 31,500 bpd. A highly intensive construction program will be needed to meet this requirement by 1980 if indeed such a goal is attainable at this starting date. Similar problems exist in the case of solid fuels. Mining of low sulfur coals requires the opening of new

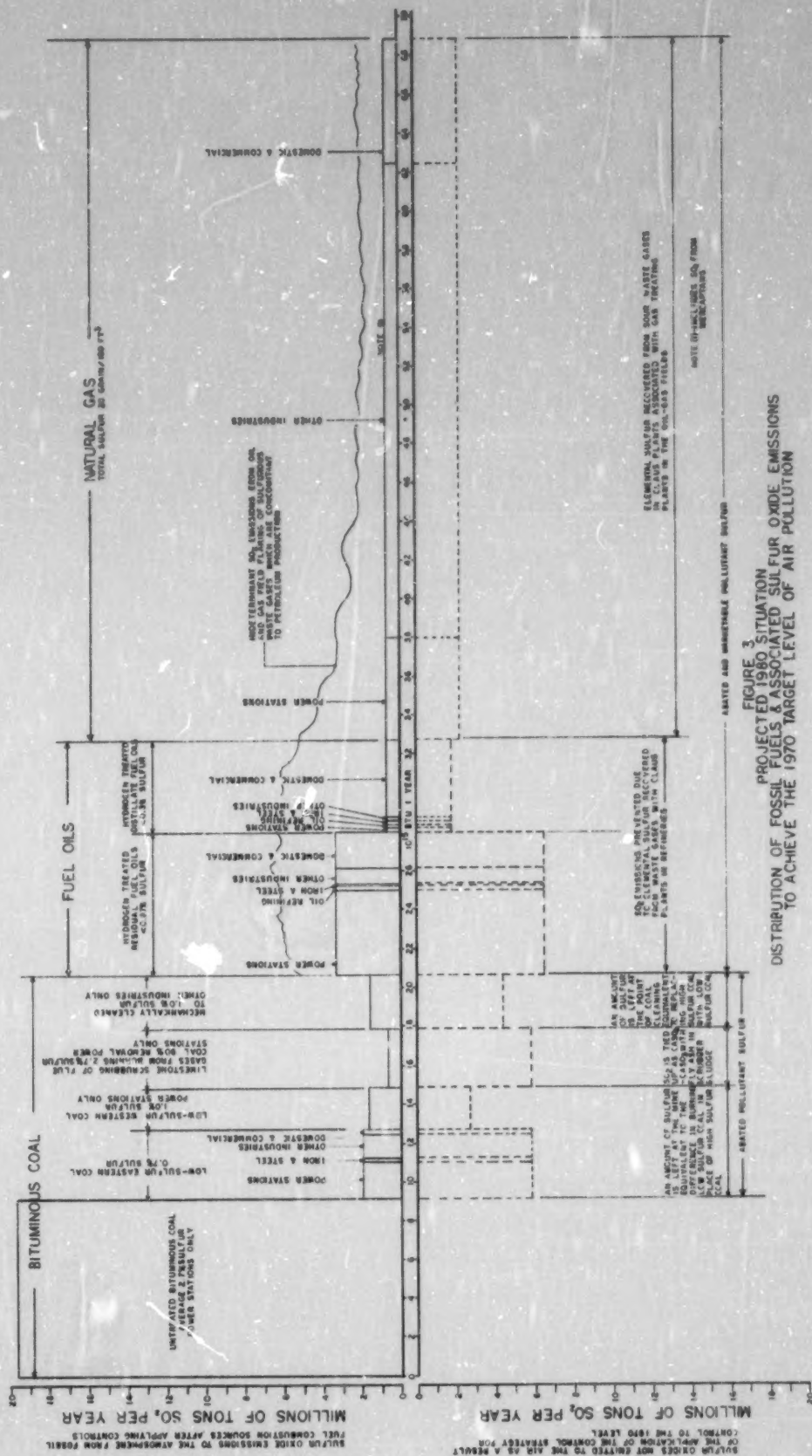
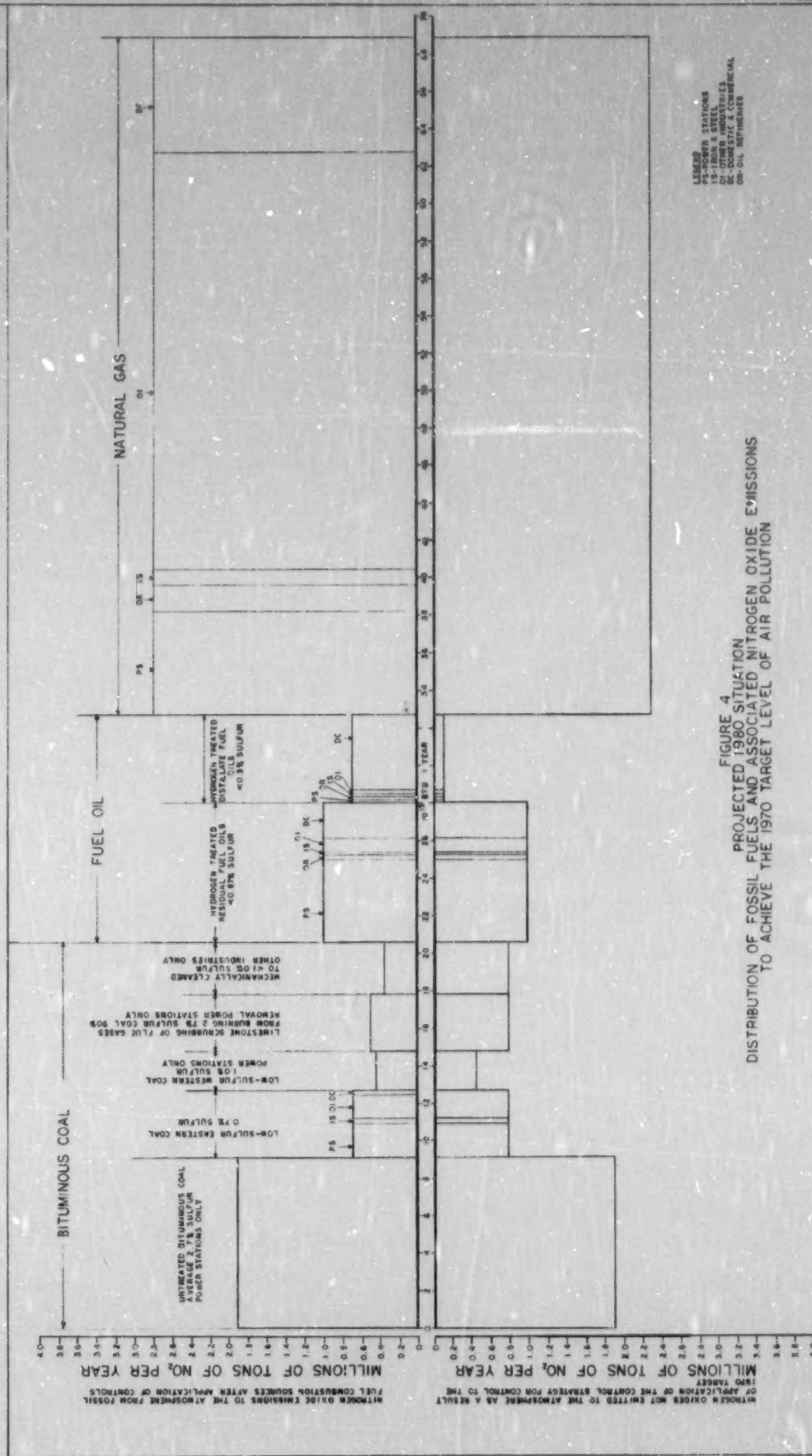


FIGURE 3
PROJECTED 1980 SITUATION
DISTRIBUTION OF FOSSIL FUELS & ASSOCIATED SULFUR OXIDE EMISSIONS
TO ACHIEVE THE 1970 TARGET LEVEL OF AIR POLLUTION



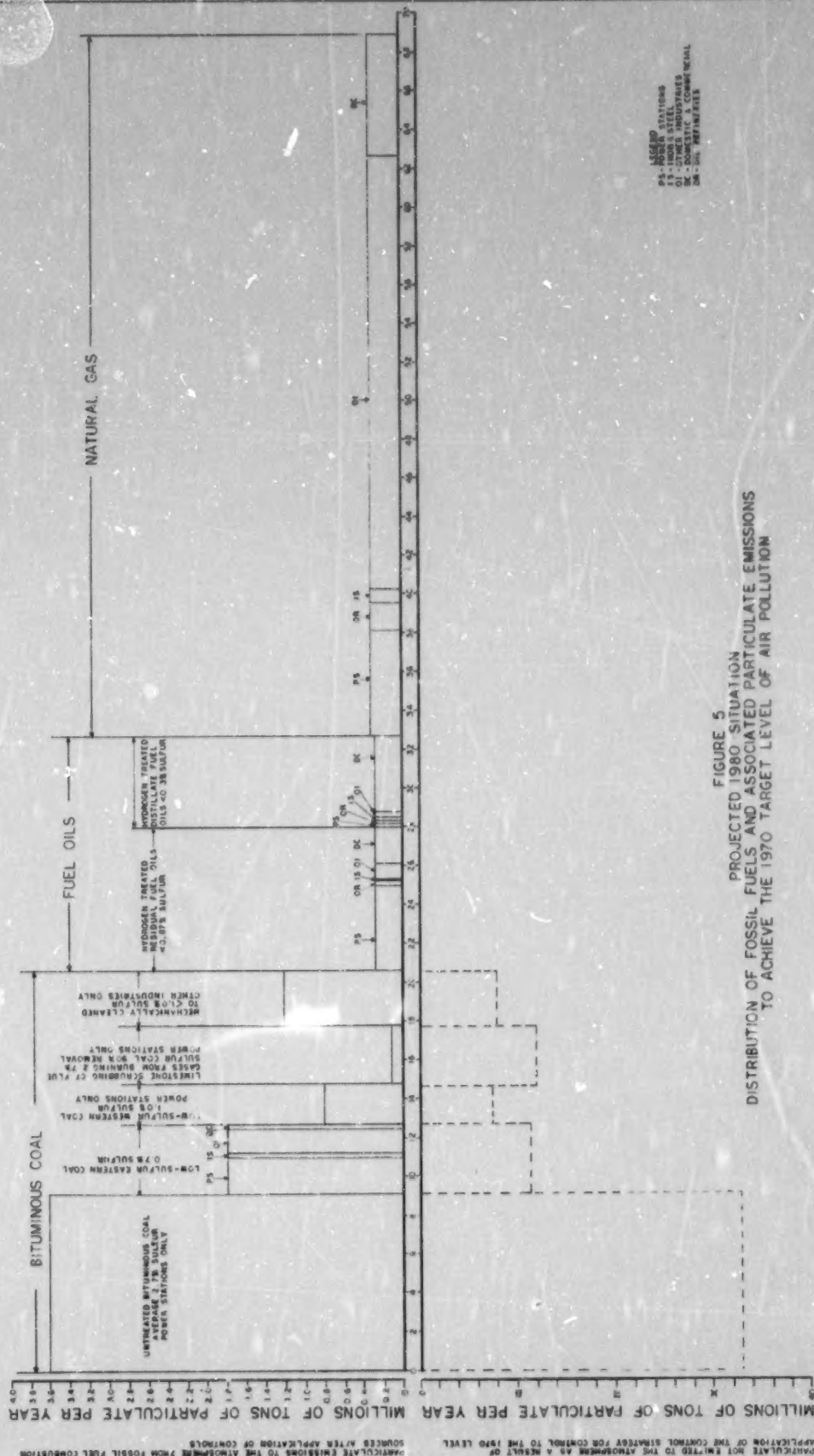


FIGURE 5
PROJECTED 1980 SITUATION
DISTRIBUTION OF FOSSIL FUELS AND ASSOCIATED PARTICULATE EMISSIONS
TO ACHIEVE THE 1970 TARGET LEVEL OF AIR POLLUTION

APPLICATION OF THE CONTROL STRATEGY FOR CONTROL TO THE 1970 LEVEL
PARTICULATE EMISSIONS TO THE ATMOSPHERE FROM FOSSIL FUEL COMBUSTION
SOURCES AFTER APPLICATION OF CONTROLS

mines at sufficient rate to meet capacity goals. Flue gas cleaning for sulfur oxides must be implemented on a large scale and the waste disposal problems must be solved satisfactorily.

The possibility of implementing the abatement strategy for limiting pollutant emissions is dependent not only on technological developments and practical demonstration of their full-scale feasibility but also, to a considerable extent, on the rate of implementation which can be attained in practice and also the timely solution of the new or alternative environmental problems introduced by such implementation. The social and economic consequences resulting from the changes in various industrial practices required by large scale implementation of abatement strategies are not defined in the study, but such changes will obviously occur. The industries most affected will in particular be power generation, petroleum refining, sulfur production, and industrial engineering and construction. The estimated total investment required to accomplish the abatement strategies for the two target levels 1970 and 1960 respectively are (billions of 1970 dollars): particulate - 1.3 and 0.72; nitrogen oxides 2.8 and 2.8; sulfur oxides - 8.6 and 9.9; total - 12.7 and 13.5.

All methods of controlling sulfur oxide and, to a large degree, particulate air pollutants have one aspect in common - in one way or another some form of the pollutant is eventually returned to the natural environment. Desulfurization processes - both those that remove sulfur compounds from fuel before combustion or from flue gas after combustion - produce sulfur compounds which may be further processed to either recover sulfur in various forms for use in the industrial or agricultural systems or for release into or storage in some suitable form in the natural environment. In any event these pollutants normally re-enter the natural environment after recovery and use since there is no conservation cycle. A satisfactory long term solution to the problem of handling the large amount of wastes generated through application of non-regenerable processes on a large scale has not yet been demonstrated.

Clean fuels will not be available in sufficient quantities to satisfy all demands. The limited supply of clean fuels as well as questions of security of supply and rational use of natural resources make fuels management an important aspect in pollution control practices. Clearly this calls for some means of allocation of clean fuels at local and national levels.

Non-combustion sources of energy production will play a considerable role in the long term but require assessment of environmental impact before widespread implementation. The use of nuclear power plants has been offered as a solution to meeting the ever-increasing demands for electrical energy. However, the impact on the ecology of the number and capacity of such installations which will be required to satisfy the needs, has not been established. Also associated with nuclear power production are the two problems of fuel production and waste disposal and the ecological consequences of these two activities. In

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addition to the analysis of long-term environmental effects, catastrophe risk must also be factored into the overall feasibility analysis.

B. Issues Arising From the Study

As indicated earlier the present study has identified a number of issues which appear to deserve more attention than they have been given in the course of this or predecessor studies. Those considered of most importance are listed below.

1) Pollution Consequences of Energy Consumption

More complete definition of the sources and amounts of pollution from combustion is needed. This applies for all three major pollutants: sulfur oxides, nitrogen oxides, and particulates. Even for sulfur oxides which have been the subject of considerable study important emissions which are associated with the production of fuels have not been included in inventories of emissions which have dealt exclusively with burning of fuels. Consequently sulfur emitted from processes which clean natural gas prior to transport and from processes which remove sulfur from distillate and residual fuels have not been included in estimates of national emissions. In attempting to evaluate these sources for the present study it was found that the necessary data for reliable estimates could not be obtained within the scope of the study. The information which was found suggests that sulfur oxide emissions from fuel production may be one of our major sources.

In a recent parallel study of natural gas processed for sulfur removal before pipeline transmission, it was determined that for about 10 percent of the annual production quantity of gas, approximately 700,000 long tons per year of sulfur are accounted for in recovery plants in the gas fields. In addition, this same gas quantity, which contains above-average sulfur as it comes from the well, accounts for about 3,400,000 tons per year of SO_x including both that which is generated through field processing and that which is generated through final use. These emissions are not included in the inventories prepared for the U. S. National Report.

For nitrogen oxides and fine particulates the overall picture is even more incomplete. For example, the nitrogen oxides produced in combustion processes is dependent both on combustion conditions and on the amount of nitrogen in the fuel. Data on the relative roles of each are almost nonexistent. For fine particulates, lack of data on the fractional efficiency of control methods, coupled with poor knowledge of the relative amounts of fine particulate produced by different combustion systems, makes resultant estimates subject to a possible wide variation.

2) Fuel Use Patterns

More detailed information is needed to define fuel consumption by industry. Some areas where little is known about the nature of the consuming processes can be identified from Table 1 and 2. For all fuels the "others" category is a balance derived by subtracting specific industry estimates from estimates for total consumption. This category represents a significant percentage of the total consumption. For gas, over one third of the total is expected to be consumed by processes which are undefined as far as their potential for pollution possibility for control, etc., are concerned. Until better information is developed it will be impossible to begin accurate assessment of possibilities for optimizing national fuel consumption practices to assure that energy demands are met in a way that prevents excessive increases in pollution and minimizes the costs for environmental protection which will be required when projected energy consumption increases become a reality.

3) Combustion Process Equipment

More detailed information on types of equipment used to burn fuels are also needed. Many types of combustion equipment, e.g., package boilers, dryers, kilns, space heaters, and water heaters may present the same pollution control problems in many industries. Better information on the character of the polluting hardware and the ways it is used would permit logical development of standards and regulations. Also it would permit identification of classes of polluting equipment which are in widespread use and would identify the best opportunities for reduction of emissions and suggest the kind of R and D needed for improved control capability. This is especially true for nitrogen oxides which are produced in quantities dictated primarily by the nature of the hardware burning the fuel and are generally not amenable to control except through modification of the combustion system. Collection of the needed data could begin with a study in which existing information on the kind and amount of fuel burned by specific types of equipment is correlated with relative contributions to air pollution. Much of the information necessary to complete such a project would not be presently available but it should be possible to accumulate existing data in a matrix which would identify certain areas of importance and show where more data are needed. Even while such a problem definition study is underway specific studies of problem areas already shown to be important could begin. For example, over 95 percent of the distillate fuel consumed in 1968 was burned by users in the "Domestic and Commercial" or "Others" categories. It seems probable that the equipment in these groups can be classified and the different types evaluated with respect to their possible importance as area sources. The resulting information should be useful in development of more effective control programs.

4) Cost For Control of Pollution From Combustion

The present study has preliminarily estimated part of the cost which could be anticipated if a control strategy of the type assumed was applied. The estimated capital requirement of \$12.0 to \$13.0 billion between now and 1980 is considered an order of magnitude figure which includes only investment directly assignable to control emissions from those processes currently burning "dirty" fossil fuels. It does not include estimates for the substantial expenditures which will be required for production facilities to meet the increased demand for gas, distillate fuels, or low sulfur coal even though much of this demand for such fuels will result from pressure to control air pollution. Further, the estimate is considered conservative in that it was based on the latest published figures, some of which are now considered ready for revision because they are unrealistically low. The annual operating cost figures of almost \$3.0 billion per year are also considered to be very rough estimates which do not reflect a true cost for control on a national basis. The calculations are also based on the best information available, but do not because of limitations imposed by data quality and report guidelines include important costs such as the incremental costs for premiums on low sulfur fuel. It is recognized that the estimated costs reported here are higher than those reported earlier and felt that this is attributable to our increasing understanding of the problem. It is believed that more definitive studies are urgently needed to provide better estimates.

5) Ultimate Disposal of Collected Pollutant

The problem of ultimate disposal of potential pollutants from combustion processes is one of great national importance which has in the past not received the attention it warrants. The planned control of pollution from combustion will produce either vast quantities of calcium sulfate sludge and fly ash from "throwaway" processes and/or large quantities of sulfur or sulfuric acid produced by by-product processes installed in the gas fields, refineries and on power stations. The magnitude of the problem can be illustrated by the following examples from present study. From Figure 3 it can be seen that under the assumed study about 6 million tons of sulfur oxide would be collected using limestone scrubbing processes. For this quantity, controlled with limestone scrubbing, it would be necessary to mine and ship to power plant sites about 20 million tons of limestone. Also it would be necessary to dispose of almost 90 million tons per year of fly ash-calcium sulfate sludge which is contaminated with soluble nitrate compounds having potential for pollution of streams and ground water.

Recovery of sulfur values as a by-product for marketing is also a solution of limited applicability. A study of future world sulfur supply and demand has predicted a continuing surplus of sulfur from conventional sources until 1985. Abatement derived sulfur will not be required until about 1990 to balance supply and demand.*

Even cleaning coal with available mechanical methods, an approach which offers the potential for reduction of most sulfur at least cost, is not without problems from the standpoint of ultimate disposal. For the assumed strategy it was calculated that 2.25 million tons of sulfur would not be emitted to the atmosphere. This would require that an estimated 21 million tons of coal cleaning refuse be stored using methods that will prevent the piles from becoming future sources of acid water drainage or air pollution from burning culm. There seems to be little question that disposal of ash and sulfur near the mine site is more economical than collection and disposal after combustion of the fuel but significant costs are still involved.

6) Meeting Future Energy Requirements

The problem of containment of air pollution from combustion processes is only one part of the greater problem of finding ways to meet future energy requirements without producing massive environmental insult. Again, reference to Figure 3 provides some indication of the potential impact of air pollution control on the problem of meeting future energy requirements. The control strategy assumes that 8.7 million tons of sulfur oxides will be prevented from entering the atmosphere by mining low sulfur coal. This means that an estimated 245 million tons of high sulfur coal which otherwise would be mined will not be mined in the year 1980 alone. This amounts to a significant new restraint being imposed on ways for meeting the 1980 fuel requirements. Costs will be incurred in opening new mines for low sulfur coal. Additional cost would doubtless be incurred because of increases in the cost to transport fuels to market. Further, the restraint in freedom to exploit our most significant source of domestic fuel will increase our degree of dependence on foreign fuels and will cause corresponding increases in the cost of fuels we import.

Figure 3 also shows that 6.6 million tons of sulfur oxides will be prevented from entering the atmosphere through the use of residual fuels desulfurized to an average of .87 percent sulfur. Production of desulfurized residual fuels would require large expansion in existing U. S. desulfurization capacity. Also it would require better than a 100 percent increase in our consumption of residual fuels which by 1980 would, if present trends continue, come almost exclusively from foreign sources.

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7) Need for National Fuels Management

Planned allocation of available clean fuel supplies is essential to accomplishing the desired reduction in emissions. It is feasible to control certain emitting sectors only by substitution of low polluting fuels and improved combustion technology. Those sectors, the domestic, commercial and certain industry activities which consist of a large number of small consumers each individually emitting near ground level can be controlled only through use of clean, non-polluting fuels and sound combustion practice. These consumers require large amounts of fuel, about 50 percent of the total energy requirements. The stimulation of the selected use of clean fuels is an important abatement practice already applied in many major localities. However, there are some such practices which are open to question regarding consumption of clean fuels by sectors more amenable to the application of other abatement practices in view of the limited availability of clean fuels.

The practice of consuming large quantities of low polluting fuels for which there are inadequate long-term reserves by high demand, large capacity users is questionable. For example, the use of natural gas to produce electricity with subsequent transmission and reconversion to heat in the home results in a loss of about 70 percent of the total chemical heat energy of the gas. The energy of the gas, if burned directly in the home to produce heat, can be recovered with some 20 percent loss in efficiency of conversion process. Thus, we can conserve some 50 percent of the energy of natural gas if converted from chemical to heat energy on site rather than going through the intermediate steps required to convert this energy to electricity and then back to heat. The increasing use of air conditioning and electrical heating in domestic and commercial sectors aggravate this problem. This practice requires closer examination and consideration in the framework of an energy management policy and activity.

8) The Impact of Fine Particle Emissions

It is important to bear in mind that with more widespread application of control techniques the relative proportion of fine particulate matter (less than 10 microns in size) emitted, compared with the larger sized particulates will increase. The impact of this relative increase in the proportion of fine particulate emissions cannot be estimated upon the existing data base.

SECTION III - CONCLUSIONS

While the present study was modest in scope and was accomplished using only data which were available from the literature, it nevertheless has served to illustrate the complexity of the interrelated problems of pollution control and energy production. Further, certain conclusions, independent of the accuracy of the data available and assumptions, can be drawn.

It can be concluded that potential for pollution from fuels combustion is increasing rapidly. Projected sulfur oxide emissions are expected, on the basis of estimated energy demand to be about twice the 25 million tons emitted in 1968 unless widespread application of control technology is practiced. A similar situation exists for nitrogen oxides, and in the case of particulates, only the continuing use of effective particulate control prevents drastic increases (approximately 10 fold) in particulate emissions. It is also apparent that avoiding massive environmental insult will be expensive. The cost to control sulfur oxides, nitrogen oxides and particulate emissions from fuel combustion to levels approximating those now existing will amount to billions of dollars per year.

It is also apparent that meeting future demand for "clean" fuel will seriously complicate the already serious problems associated with meeting future energy requirements for the U. S. National planning will be required to assure that the needed mix of fuels is available at any price. Our most abundant fuel, coal, is usually high in sulfur which often is not amenable to removal prior to combustion. It is apparent that we will be required to use all available means including desulfurization of fuels where possible, substitution of low sulfur fuels where available, and stack gas cleaning where necessary to meet energy demands without undesirable levels of pollution, unacceptable economic impact or dependence on foreign supplies of fuel. The problem is not limited to potential pollution from power generation. Containment of pollution from burning of fuels for domestic, commercial and industrial purposes other than power production will require management of the production and consumption of low sulfur fuels, particularly gas and distillate fuels.

Meeting 1980 demand for the distillate fuels which will be required to minimize pollution calls for planned expansions of refinery facilities and consideration of adjustment to fuel regulation policies, particularly those relating to import regulations, to assure that necessary facilities can be available by 1980 without unnecessary investment abroad.

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It is also clear that action is needed now to assure that technology which will be needed in the immediate future is made available. Many of the techniques which will be needed to control pollution from combustion in 1980 and beyond are still under development. Stack gas cleaning systems and processes for conversion of coal to "clean" fuel are the most important examples of technology which must be developed, demonstrated and utilized in the shortest possible time to meet future needs. Means for controlling nitrogen oxides from combustion systems must be developed to a much higher degree before significant reductions in national emissions will be possible. Also our present capability for control of very fine particulates and particulates which are emitted with offensive co-contaminants is inadequate for future needs.

Further it is apparent that better data and more sophisticated methods for forecasting, planning, and managing our fuels production and consumption practices are needed. Many examples can be cited. We are still in doubt as to the relative importance of urban, rural and global effects and the relative importance of area sources and point sources is understood only in a qualitative way. This lack of understanding leads to difficulties in setting meaningful priorities for emission control. We are also faced with many anomalies in the present practices of fuel utilization.

At a time when natural gas needs to be conserved regulatory and price control practices encourage consumption and act to discourage exploration to identify new reserves. We are facing possible power shortages yet utilities continue to encourage higher consumption. We continuously strive for increases in the efficiency with which we use fuels and at the same time we burn gas to produce electricity and use electricity to heat homes when direct use of gas for heating would prevent a 50 percent loss of the energy in the gas. At a time when it is apparent that great national savings could be realized by using available technology to remove large amounts of ash and sulfur at the mine we continue to pay unnecessary penalties for transport of ash, overdesign of boilers to accommodate lower quality fuel, and in the form of higher costs to remove the larger quantities of particulates and sulfur oxides from the products of power station combustion.

It is apparent that great changes in the traditional approaches to production and consumption of fuels can be expected between now and 1980. Nationally, our expectations for a clean environment are in conflict with our ambitions for continued economic growth... changes in fuels management practices will be the key to reaching a satisfactory compromise.

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SECTION IV

U. S. NATIONAL REPORT TO THE
JOINT GROUP ON AIR POLLUTION FROM
FUEL COMBUSTION IN STATIONARY SOURCES -
ORGANIZATION FOR ECONOMIC COOPERATION AND DEVELOPMENT

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THE U. S. NATIONAL REPORT TO THE O.E.C.D.

JOINT GROUP ON AIR POLLUTION

FROM

FUEL COMBUSTION

JUNE 11, 1971

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AIR POLLUTION FROM FOSSIL FUEL
COMBUSTION IN STATIONARY SOURCES
IN THE UNITED STATES

PREFACE

1. This report has been prepared to conform to the criteria established by O.E.C.D. in "A Report on Air Pollution from Fuel Combustion in Stationary Sources as A Guideline for National Reporting".
2. The rates of emission of the specific air pollutants NO_x , SO_x , and particulates that result from burning fossil fuels have been calculated for the years 1960 and 1970. The emissions have been calculated from the most recent data on how much of these pollutants the various fuels produce under varying conditions of burning. These data show how the pollutant picture has changed in the last decade in the United States.
3. Fossil fuel consumptions have been predicted for 1980, and from these predictions, the uncontrolled pollutant emissions have been determined using the same methodology as 1960 and 1970. Therefore, each fuel and industry sector can be considered for its effect on air pollution.
4. An overall strategy for reducing the pollution of various sectors has been presented. This strategy has been applied to show means for reducing pollutant emissions to either 1970 levels (a 42 percent reduction in potential emissions for NO_x and a 54 percent reduction in projected emissions for SO_x) or 1960 levels (a 67 percent reduction in projected levels for NO_x and a 63 percent reduction in projected SO_x emissions). The state of the technology is sufficiently well developed that the strategy can be regarded as technically feasible. The situation in the United States for establishing and accomplishing air quality goals is in a rapidly evolving state at this time. The concept of National Emission Standards and Standards of Performance for certain industrial segments was instituted by the Clean Air Act of 1970. Because the situation has been rapidly changing, even during the preparation of the U. S. National Report, it is not possible to indicate how well the estimates contained in the National Report will truly represent the future picture as dictated by the mechanisms finally adopted for achieving clean air.

One of the formidable problems encountered was the rationalization for and selection of the targeted emission levels. Because such levels are only now being established through the basis of the Clean Air Act of 1970, i.e., basis of best demonstrated control, the level of emission control could not be based on permissible emission factors or on ambient air quality guides. Target goals are based on control to 1960 and 1970 levels to provide at least some order-of-magnitude estimate for total national control.

5. Costs have been developed to estimate some of the important national costs for holding 1980 emissions to the levels estimated for 1960 and 1970.

CHAPTER I

POLLUTANT EMISSIONS FROM BURNING FOSSIL FUELS

1. A modern industrial society consumes large quantities of fossil fuel, converting it to energy by burning. Sulfur oxides, nitrogen oxides, and particulates (unburned carbon and nonburnable ash) are the main pollutants emitted by stationary fuel combustion sources. Other pollutants emitted from these stationary sources are carbon monoxide, cyanides, hydrocarbons, and trace minerals, as well as waste heat. This report deals only with NO_x , SO_x , and particulates emitted in the United States.

2. The stationary sources of pollution from burning fossil fuels have been divided into various user-oriented categories. These categories per O.E.C.D. guidelines are:

- (a) Power stations
- (b) Oil and gas production
- (c) Oil refineries
- (d) Coke ovens
- (e) Iron and steel
- (f) Cement
- (g) Other industries
- (h) Domestic and commercial

The use of these categories gives groupings of similar pollution sources. It permits air pollution due to operation of a specific process (such as iron oxides from steel furnaces) to be cataloged separately from the air pollution which emanates from the fossil fuel. Also, it permits quantification of emission contributions from various sectors, e.g., homes burning gas produce one-fourth as much NO_x as power stations burning gas (Tables 6 and 8).

3. In some situations certain operations overlapped more than one sector as defined by O.E.C.D. For example in 1967 in the "iron and steel" sector 28 percent of the electricity was self-generated and 72 percent was purchased from the "power stations" sector. For reporting purposes, the 28 percent was reported with the power station category. This same situation of part purchase and part generation is found in many other areas such as chemicals, cement, and commercial buildings and was handled in the same way. Another closely coupled interrelation is between coking ovens and iron and steel (see Annex III-2) where coke oven gas predominantly goes into steel plants and blast furnace gas predominantly goes into coke ovens (References 8, 10). For reporting purposes, emissions from combustion of coke oven gases were included with iron and steel while emissions from combustion of blast furnace gas was assigned to the coke ovens sector.

4. Using the fuel consumption rate for a given sector, the SO_x emitted can be assigned to that sector as a whole. This can be seen in Tables 6, 7, and 8. These figures give the total SO_x for the United States with one exception. Natural gas is produced in the oil fields and gas fields and generally contains hydrogen sulfide. This is removed before the gas is put into pipelines for use. Much of the hydrogen sulfide is burned to SO_x in the fields, along with natural gas, to get energy to run the collection system. In this way the clean gas burned in the power stations and homes creates SO_x in the fields. These emissions which by the guidelines supplied should be charged to the oil refineries sector, could not be accounted for despite the fact that they may represent a significant percent of the total now and in the future.

5. It should be noted that less is known about nitrogen oxides concerning how they pollute and how they are formed. If nitrogen compounds are present in fuel, some of them will appear in the combustion gases (see Annex V-5). In addition, high temperature combustion in air causes NO_x to form from the nitrogen in the air; this is a situation usually present with high excess air (Reference 11). Coal is the only major fuel for which nitrogen oxide emission data are generally available; emission factors for gas and oil firing are less reliable so that an unquantified bias may be present in the data.

6. For purposes of the report all emissions were tabulated under the industry in which the fuel was burned and when costs to control were calculated, it was done on the basis of cost to remove sulfur at the point in the production-consumption cycle dictated by the control strategy. As a result, it was not possible to break costs down by industry, and national totals are shown.

7. The consumption of fossil fuels in the various sectors in the United States for 1960 is shown in Table 1. The pollutant emissions for 1960 were calculated by using emission factors of Tables 15, 16, 17, and 18.

8. Stack gas emissions from burning fossil fuels in 1960 are summarized in Table 2. For this table, all the rates have been converted into metric units. The fuel oil equivalent for all those fuels was calculated on the basis that 1 million metric tons of heavy oil had a higher heating value of 41.91×10^{12} Btu.

9. Fuel rates for 1968 are shown in Table 3 and the rates for 1970 are shown in Table 4. O.E.C.D. has chosen 1968 for a base year, but for convenience in preparation of this report 1970 has been selected as a base year. The pollutant emissions for 1970 are shown in metric units in Table 5.

10. Since 1966, virtually all new, large, coal-fired boilers and furnaces have been erected with either a high efficiency wet scrubber or an electrostatic precipitator as an integral component (References 6, 14, 15, 16, 17, 18). This has come about due to legislation and competitive pressures as well as improved technology.

11. The 1980 particulate emissions controlled to 1970 and 1960 levels are on an assumed strategy basis which is achievable. It is anticipated that high efficiency electrostatic precipitators will be installed on the majority of plants by 1980. This would result in total particulate emissions being reduced below the levels controlled to 1960 shown in this report (Table 9).

TABLE 1
UNITED STATES FOSSIL
FUEL CONSUMPTION
1960

	POWER STATION	COKE OVEN	OIL REFINERY	OIL PRODUCT.	IRON & STEEL	CEMENT	OTHER	DOMEST. & COMC'L.
NATURAL GAS	1723. x 10 ⁹ ft.3	5 x 10 ⁹ ft.3	775. x 10 ⁹ ft.3	2122 x 10 ⁹ ft.3	378 x 10 ⁹ ft.3	171.3 x 10 ⁹ ft.3	5528 x 10 ⁹ ft.3	4122 x 10 ⁹ ft.3
MANUFAC TURED GAS	27.63 x 10 ⁹ ft.3	302.7 x 10 ⁹ ft.3			380.2 x 10 ⁹ ft.3	0.7 x 10 ⁹ ft.3	n.a.	27.64 x 10 ⁹ ft.3
FLAST FURNACE GAS		337.7 x 10 ⁹ ft.3			n.a.			
REFINERY GAS								
L.P.G.					7.96 x 10 ⁶ Gals.		199. x 10 ⁶ Gals.	1950. x 10 ⁶ Gals.
HEAVY FUEL OIL	95.4 x 10 ⁶ Bbls.		45.05 x 10 ⁶ Bbls.		49.50 x 10 ⁶ Bbls.	4.035 x 10 ⁶ Bbls.	115.8 x 10 ⁶ Bbls.	125.0 x 10 ⁶ Bbls.
FUEL OIL	4.746 x 10 ⁶ Bbls.		8.34 x 10 ⁶ Bbls.				34.25 x 10 ⁶ Bbls.	438. x 10 ⁶ Bbls.
BROWN COAL	2.289 x 10 ⁶ Tons							
HARD COAL	172. x 10 ⁶ Tons				7.57 x 10 ⁶ Tons	8.27 x 10 ⁶ Tons	82.90 x 10 ⁶ Tons	40.25 x 10 ⁶ Tons
COKE	n.a.						n.a.	n.a.

n.a. = data not available.

Regional Group - United States

TABLE 2
CONSUMPTION OF FUEL
AND RESULTING STACK GAS EMISSIONS
(DERIVED FROM TABLE 1 DATA)

Year 1960
Original OECD Figures
and million tons oil
equivalent

Sectors	Type of Fuel	Fuel Units	Fuel Rate	SO ₂ Millions of Metric Tons	SO _x Millions of Metric Tons	Particulate Millions of Metric Tons	Fuel Rate Million Metric Tons Oil equivalent
Public power stations	Natural gas	Total	457.8 x 10 ¹²	0.305	0.001	0.012	43.5
	Manufactured gas	"	3.79 x 10 ¹²	0.003	0.018	neg.	0.36
	Light fuel oil	thousand metric tons	660.0	0.010	0.005	0.001	0.66
	Heavy fuel oil	"	12,850.	1.190	8.020	0.015	12.85
	Hard coal	"	96,900.	0.021	0.040	2.675	96.90
Blast furnace gas and B.K.B. not applicable	Brown coal	"	1,090.	n.a.	n.a.	0.035	1.09
	Coke	"	n.a.	n.a.	n.a.	n.a.	n.a.
	Total		-	2.049	8.825	2.738	135.36
	Natural gas	Total	675.0 x 10 ¹²	0.825	0.001	0.236	63.22
	Light fuel oil	thousand metric tons	1,160.	0.011	0.007	0.004	1.16
Refineries	Heavy fuel oil	"	6,780.	0.057	0.350	0.017	6.78
	Total		-	0.893	0.358	0.257	71.16
	Blast furnace gas	Total	8.06 x 10 ¹²	0.004	neg.	0.003	0.766
	Manufactured gas	"	41.77 x 10 ¹²	0.015	0.194	0.003	3.97
	Natural gas	"	1.26 x 10 ¹²	neg.	neg.	neg.	0.12
Coke-ovens	Total		-	0.019	0.194	0.006	4.856
	Natural gas	Total	95.28 x 10 ¹²	0.036	neg.	0.003	9.435
	Manufactured gas	"	52.54 x 10 ¹²	0.019	0.245	0.003	0.245
	Blast furnace gas	"	n.a.	n.a.	n.a.	n.a.	n.a.
	Heavy fuel oil	thousand metric tons	7,450.	0.068	0.386	0.019	7.45
Iron and steel	Light fuel oil	"	20.	neg.	neg.	0.02	0.02
	Heavy fuel oil	"	4,260.	0.069	0.354	0.236	4.26
	Hard coal	"	18.	neg.	neg.	neg.	0.018
	L.P.G.	"	-	0.192	0.985	0.261	26.155
	Total		-	0.552	0.002	0.047	137.9
Other industries	Natural gas	Total	1,451.0 x 10 ¹²	n.a.	n.a.	n.a.	n.a.
	Manufactured gas	"	n.a.	n.a.	n.a.	n.a.	n.a.
	Light fuel oil	thousand metric tons	4,760.	0.047	0.028	0.013	4.76
	Heavy fuel oil	"	17,420.	0.068	0.930	0.045	17.42
	Hard coal	"	46,700.	0.069	4.230	2.830	46.7
Blast furnace gas, Brown coal and B.K.B. not applicable	L.P.G.	"	450.	0.004	neg.	0.001	0.45
	Total		-	0.740	5.190	2.936	207.23
	Natural gas	Total	1,082. x 10 ¹²	0.140	0.001	0.035	102.8
	Manufactured gas	"	3.79 x 10 ¹²	0.001	0.018	neg.	0.36
	Light fuel oil	thousand metric tons	60,900.	0.354	0.356	0.083	60.9
Domestic and others	Heavy fuel oil	"	18,800.	0.146	0.971	0.024	18.8
	Hard coal	"	22,680.	0.146	1.968	0.365	22.68
	L.P.G.	"	4,440.	0.035	neg.	0.006	4.44
	Total		-	0.776	3.314	0.513	209.98
	Total		-	4.709	18.866	6.710	674.761
GRAND TOTAL							

n.a. = data not available
neg. = less than 0.001

TABLE 3
UNITED STATES FOSSIL
FUEL CONSUMPTION
1968

	POWER STATION	COKE OVEN	OIL REFINERY	OIL PRODUCT,	IRON & STEEL	CEMENT	OTHER	DOMEST. & COMC'L.
NATURAL GAS	3148 x 10 ⁹ ft. 3	0.94 x 10 ⁹ ft. 3	1.59 x 10 ¹² ft. 3	1.07 x 10 ¹² ft. 3	509 x 10 ⁹ ft. 3	202.9 x 10 ⁹ ft. 3	6.69 x 10 ¹² ft. 3	6.25 x 10 ¹² ft. 3
MANUFAC TURED GAS	91.9 x 10 ⁹ ft. 3	331.8 x 10 ⁹ ft. 3			904 x 10 ⁹ ft. 3		22.15 x 10 ⁹ ft. 3	14.84 x 10 ⁹ ft. 3
BLAST FURNACE GAS		552 x 10 ⁹ ft. 3			3.99 x 10 ¹² ft. 3			
REFINERY GAS								
L.P.G.					14.61 x 10 ⁶ Gals.		n.a.	n.a.
HEAVY FUEL OIL	185 x 10 ⁶ Bbls.		39.3 x 10 ⁶ Bbls.		23.85 x 10 ⁶ Bbls.	5.76 x 10 ⁶ Bbls.	114.4 x 10 ⁶ Bbls.	174.3 x 10 ⁶ Bbls.
FUEL OIL	8.51 x 10 ⁶ Bbls.		9.97 x 10 ⁶ Bbls.		8.02 x 10 ⁶ Bbls.		49.3 x 10 ⁶ Bbls.	510.7 x 10 ⁶ Bbls.
BROWN COAL	6 x 10 ⁶ Tons							
HARD COAL	297.8 x 10 ⁶ Tons				6.62 x 10 ⁶ Tons	9.5 x 10 ⁶ Tons	84.43 x 10 ⁶ Tons	19.97 x 10 ⁶ Tons
COKE	9.16 x 10 ⁶ Tons							

n.a. = data not available.

TABLE 4
UNITED STATES FOSSIL
FUEL CONSUMPTION
1970

	POWER STATION	COKE OVEN	OIL REFINERY	OIL PRODUCT.	IRON & STEEL	CEMENT	OTHER	DOMEST. & COMC'L.
NATURAL GAS	3.45×10^{12} ft. ³	1.09×10^9 ft. ³	1.029×10^{12} ft. ³	$691. \times 10^9$ ft. ³	497.5×10^9 ft. ³	213.7×10^9 ft. ³	10.83×10^{12} ft. ³	7.00×10^{12} ft. ³
MANUFACTURED GAS	91.3×10^9 ft. ³	329.5×10^9 ft. ³			$883. \times 10^9$ ft. ³		22.0×10^9 ft. ³	14×10^9 ft. ³
BLAST FURNACE GAS		547.5×10^9 ft. ³			3.898×10^{12}			
REFINERY GAS								
L.P.G.					14.29×10^6 Gals.		n.a.	n.a.
HEAVY FUEL OIL	309×10^6 Bbls.		39.1×10^6 Bbls.		23.33×10^6 Bbls.	6.08×10^6 Bbls.	$106. \times 10^6$ Bbls.	190×10^6 Bbls.
FUEL OIL	14.0×10^6 Bbls.		13.23×10^6 Bbls.		7.835×10^6 Bbls.		42.12×10^6 Bbls.	575×10^6 Bbls.
BROWN COAL	7.51×10^6 Tons							
HARD COAL	316.0×10^6 Tons				6.46×10^6 Tons	10×10^6 Tons	133.8×10^6 Tons	20.0×10^6 Tons
COKE	9.16×10^6 Tons							

n.a. = data not available.

Year 1970
Original OECD Figures
and million tons oil
equivalent

TABLE 5
CONSUMPTION OF FUEL
AND RESULTING STACK GAS EMISSIONS
(DERIVED FROM TABLE 4 DATA)

Regional Group - United States

Sectors	Type of Fuel	Fuel Units	Fuel Rate	NO _x Millions of Metric Tons	SO ₂ Millions of Metric Tons	Particulate Millions of Metric Tons	Fuel Rate Million Metric Tons Oil equivalent
Public power stations	Natural gas	Total	906. x 10 ¹²	0.608	0.001	0.024	86.16
	Manufactured gas	"	12.63 x 10 ¹²	0.008	0.059	0.001	1.20
	Light fuel oil	"	1,770.	0.028	0.013	0.002	1.77
	Heavy fuel oil	"	46,480.	0.617	2.403	0.047	46.48
	Hard coal	"	178,000.	2.866	14.690	4.900	178.0
Blast furnace gas and B.K.B. not applicable	Brown coal	"	2,975.	0.068	0.130	0.117	2.975
	Coke	"	4,810	0.084	0.158	0.142	4.81
	Total		-	4.279	17.454	5.233	321.395
Refineries	Natural gas	Total	441.0 x 10 ¹²	1.090	0.001	0.014	42.92
	Light fuel oil	"	1,670.	0.017	0.011	0.005	1.67
	Heavy fuel oil	"	5,880.	0.050	0.305	0.015	5.88
Coke-ovens	Total		-	1.157	0.317	0.034	50.470
	Blast furnace gas	Total	13.07 x 10 ¹²	neg.	0.005	0.004	1.243
	Manufactured gas	"	45.51 x 10 ¹²	0.016	0.212	0.003	4.328
Coke not consumed as a fuel	Natural gas	"	0.28 x 10 ¹²	neg.	neg.	neg.	0.027
	Total		-	0.016	0.217	0.007	5.598
Iron and steel	Natural gas	Total	130.6 x 10 ¹²	0.047	neg.	0.005	12.42
	Manufactured gas	"	120.8 x 10 ¹²	0.044	0.563	0.007	11.58
	Blast furnace gas	"	95.04 x 10 ¹²	neg.	neg.	neg.	9.036
	Heavy fuel oil	"	3,512.	0.032	0.181	0.009	3.512
	Light fuel oil	"	989.	0.011	0.006	0.003	0.989
Coke not consumed as a fuel	Hard coal	"	3,660.	0.059	0.299	0.200	3.66
	L.P.G.	"	36.	neg.	neg.	neg.	0.036
	Total		-	0.193	1.049	0.224	41.233
Other industries	Natural gas	Total	2,898. x 10 ¹²	1.073	0.003	0.091	275.5
	Manufactured gas	"	3.05 x 10 ¹²	neg.	0.018	neg.	0.29
	Light fuel oil	"	5,315.	0.058	0.034	0.016	5.315
	Heavy fuel oil	"	16,870.	0.153	0.872	0.044	16.87
	Hard coal	"	81,050.	1.306	6.675	4.835	81.05
Brown coal and B.K.B. not applicable	L.P.G.	"	n.a.	n.a.	n.a.	n.a.	n.a.
	Total		-	2.590	7.602	4.986	379.025
Domestic and others	Natural gas	Total	1,837. x 10 ¹²	0.231	0.003	0.061	174.6
	Manufactured gas	"	1.90 x 10 ¹²	neg.	0.009	neg.	0.18
	Light fuel oil	"	72,600.	0.463	0.468	0.109	72.60
	Heavy fuel oil	"	28,580.	0.153	1.478	0.036	28.58
	Hard coal	"	11,260.	0.073	0.534	0.101	11.26
Blast furnace gas, B.K.B., patent fuel, coke, and brown coal not applicable	L.P.G.	"	n.a.	n.a.	n.a.	n.a.	n.a.
	Total		-	0.919	2.892	0.387	287.22
	Total		-	9.154	29.532	10.871	1084.941

n.a. = data not available
neg. = less than 0.001

CHAPTER II

ALTERNATE POLLUTION ABATEMENT TECHNIQUES

12. Many methods for pollution abatement are under investigation and in various stages of development. An attempt is made herein to give a brief description of those more suitable for large scale application in the immediate future.

13. The rate at which technology under development can be made operational on a significant scale must be considered before deciding on a control strategy to be applied in the next 10 years. Processes in advanced development now can have significant impact by 1980. A process for catalytic oxidation of SO_2 and O_2 in the flue gases to produce SO_3 which reacts with H_2O to produce H_2SO_4 is being scaled up to control a full scale boiler. Also at present, limestone-based processes are processes being studied on full scale equipment. On the basis of this work, it is assumed that flue gas cleaning would be used along with fuel substitution to achieve the desired level of control. For simplicity in developing costs, all flue gas cleaning will be limestone scrubbing even though other processes may be in service in 1980.

14. Methods of pollution abatement that are suitable for use will vary with the size of the installation. Intermediate sized commercial and industrial boilers have the least number of options available of all the stationary pollutant emitters, due primarily to their small size and non-standard installations. Being small, owners frequently cannot negotiate long-term contracts for any particular fuel. With the government regulating gas distribution to ensure that it gets to domestic and service users (such as hospitals), they cannot readily use alternate fuels. Their small size makes any stack scrubbing system very costly.

15. Obviously, processes that reduce pollution loads for all three of the major pollutants simultaneously are desirable. Methods to achieve simultaneous reductions are described below.

- (a) Nuclear energy is air pollution free with respect to the three major pollutants under consideration. It does, however, present other problems, such as thermal pollution, air contamination from radioactive gases, and contamination from radioactive solid and liquid wastes and pollution which results from fuel reprocessing. The rate of increase in

nuclear generating capacity in the next nine years will not be great enough to prevent large increases in fossil fuel pollution (Reference 37).

- (b) Tall stacks have been widely used to dispense pollutants. Furthermore, the criterion of tall stacks is inherent in many local laws restricting the sulfur content of fuels burned. However, if pollution from combustion is to be considered as a problem which should not be passed on without consent to neighboring countries, this approach cannot be considered as a satisfactory solution to international problems.
- (c) Fuel substitution is the most direct and simplest method of reducing air pollution from any stationary source. This can consist of using a higher quality fuel of the same type, e.g., low sulfur coal instead of high sulfur coal; or of changing the type of fuel, e.g., using natural gas instead of coal. The extent of fuel substitution which is possible in the United States is seriously limited by the size and accessibility of reserves of low pollution fuels.
- (d) Gas turbines have become significant factors in power generation in the last few years. They are low cost units generating electricity from a gas and emitting little in the way of air pollutants (see Tables 15 and 18). However, they have low efficiency (References 20, 22) operating at 24 percent compared to a steam electric plant using gas at 33 percent. If the government did not regulate prices, their economic advantages would be materially decreased. The main impact they have on pollution is that turbines consume more of a clean fuel to generate a given quantity of electricity than does a steam plant. Since natural gas is in short supply, widespread use of gas turbines in power generation is not desirable on a long-term basis except as they may be adapted for use with gas produced from coal or residual oil. Where they can be used with cleaned gas produced from residual oil or coal in combined gas-steam cycles they are believed to offer potential efficiency which will offset significant portions of the cost to control pollution beyond 1980.

- (e) Fluid bed combustion, in which the burning fuel is combined with a bed consisting mainly of limestone particles, offers a potential method for reduction of sulfur oxide and nitrogen oxides. This process is in early development stages, and it is consequently not possible to establish what pollution reductions can be attained and what the engineering design parameters are for full scale operation. There is little likelihood that it can be used to any great extent by 1980. (Reference 32)
- (f) Coal can be converted to a low calorific value gas suitable for power generation by gasification with air. The sulfur and particulates can be removed from the smaller volume of gas much more economically than they can from the larger volumes of combustion flue gas. This gas must be produced at the site where it is to be used because pipeline transportation costs are excessive for a low heating value gas. Coal gasification to make a substitute natural gas with a high heating value is also technically feasible, but time required for necessary development and construction of processes makes it unlikely that this approach will contribute to control of pollution in the next nine years.

16. For the control of sulfur oxides, specifically, the following methods can be utilized:

- (a) Fuel substitution by mining more low sulfur coal to replace some of the high sulfur coal being used. There are large reserves of low sulfur coal, particularly in the western United States. However, their use has been restricted because their location is remote from users so that use in the east would result in high transportation cost. With the pressing need for low sulfur fuels, mining of more of this coal can be justified.
- (b) The mechanical desulfurization of coal is one of the cheapest ways to reduce SO_x . Coal preparation or coal washing has been a standard commercial practice for many years. In most instances the coal was cleaned to reduce the ash content of the coal. Until recently, little attention was paid to the special problem of sulfur reduction by coal preparation. Studies of coal seams have shown that there are large reserves of coal which can be deep cleaned to less than 1 percent pyritic sulfur content.

- (c) Desulfurization of residual fuel oil to 1 percent sulfur, or less, is commercially feasible and is practiced to a limited extent. Most of the processes are in the development stage, and costs are high. Research to achieve better catalysts and catalyst life, higher throughput, lower operating temperatures and pressures, and reduction in hydrogen consumption, should result in reduced costs.
- (d) There are a number of flue gas cleaning processes in various stages of development. These are classified as either throw-away processes, with SO_x removed as a waste product, or by-product recovery, with recovery of sulfur or sulfuric acid. The most promising of the throw-away processes are limestone injection and wet scrubbing or lime scrubbing. These have been under development for some time, but remain to be proved reliable on a commercial scale. The large quantities of sludge formed present a disposal problem. Other throw-away processes are sodium bicarbonate dry injection and ammonia scrubbing with recovery of ammonia. The former presents the problem of disposing of water-soluble sodium sulfate, and the latter presents a solid waste disposal problem. By-product recovery processes, such as magnesium oxide scrubbing, potassium sulfite, and catalytic oxidation have yet to be demonstrated on a commercial scale.

17. The control of NO_x as an air pollutant is in need of further research. Any high temperature combustion process using air as a source of oxygen forms NO_x from the nitrogen in the air. Any fuel containing nitrogen will also form NO_x by oxidizing of the nitrogenous material. Fieldwork on full scale boilers has shown that by various combinations of techniques, NO_x can be held down to 200 ppm in the stack gas as discussed in Annex VII. The three most practicable methods in terms of technology today are:

- (a) Low excess air. A low proportion of air above the stoichiometric amount to oxidize the fuel, in the order of about 10 percent by volume, permits fuel combustion to take place with a low formation of NO_x .
- (b) Flue gas recirculation. Returning about 10 percent of the stack gas back into the flame zone of a boiler or furnace has a measureable effect on NO_x formation, as pointed out in Annex VII.

- (c) Two-stage combustion which employs a lower temperature reducing atmosphere section, i.e., less than stoichiometric air, followed by a second oxidizing atmosphere section. The design is highly specialized, and since the technology has not become widespread, this was not considered in the strategy.

19. Fluid bed combustion has come to the fore as a promising technique of burning coal in a fluidized bed of limestone. The limestone effectively ties up the sulfur to materially reduce SO_x emissions but its benefits on NO_x depend on the fuel. This is currently confined to the pilot plant stage, and therefore was not considered part of the abatement strategy.

20. A side benefit of SO_x reduction using wet alkali scrubbing of stack gases is some reduction in the NO_x . A 20 percent removal was assumed for calculation of emissions. The effectiveness is lower for NO_x than for SO_x , so its benefit is incidental. The benefit is shown in Table 9 compared to Table 8 where the 1960 level emissions are lower than the 1970 level emissions as a result of more extensive scrubbing to reduce SO_x . The strategy for combustion control in 1970 control is the same as in 1960, but the lower NO_x is due to more limestone scrubbing.

21. Control of particulate emission is the area where technology is the most advanced and widespread. In the United States the trend to control has been almost universal for all industry sectors, and coal-fired furnaces have installed, since 1966, either electrostatic precipitators or high energy wet scrubbers. By 1980 it is projected that all coal-fired equipment will have particulate collection equipment. The potential for emissions is shown in Table 7 (over 73 million tons). It is anticipated that the actual emissions for 1980 will be well below the 1960 level of 6.7 million tons.

CHAPTER III

POLLUTANT ABATEMENT STRATEGY FOR THE UNITED STATES

22. Because sulfur oxide control is the most important consideration in control of pollution from combustion, the control strategy which was developed was aimed primarily at maximum reduction in this pollutant. Incidental benefits in NO_x and particulate control resulting from application of SO_x control technology were factored into subsidiary programs for NO_x and particulate control. Details of assumed strategies are discussed in Chapter IV.

23. No single approach for control of SO_x can be considered practical within the next ten years. Fuel substitution is limited by the supplies of clean fuels. Flue gas scrubbing, even with well developed technology, presents other problems such as disposal of large quantities of sludge and possible water pollution. For purpose of this report, tall stacks are not to be considered as a positive control measure for pollutant capture. The strategy in the O.E.C.D. Guideline report of limiting the sulfur content of oil and substituting low sulfur oil for coal has been ruled out because existing legislation already limits the sulfur content of oil in many areas. In addition, the total available quantity of oil in 1980 is not expected to be sufficient to allow its complete substitution for coal.

24. The strategy proposed includes a combination of four methods for the control of SO_x . These are:

- (a) Increased mining of low sulfur coal.
- (b) Mechanical desulfurization of coal as described in Annex VI.
- (c) Residual oil desulfurization as described in Annex VI.
- (d) Flue gas cleaning by wet limestone scrubbing as discussed in Annex VIII.

25. For control of NO_x , the only known means likely to be implemented on a large scale by 1980 is improved combustion techniques for lowering operating temperatures. This is discussed in Annex VII.

26. Particulates are expected to be controlled by the increased use of electrostatic precipitators, following current trends, in addition to the stack scrubbers used for SO_x control.

CHAPTER IV

THE PROJECTED SITUATION FOR 1980

27. The consumption of fossil fuels in 1980 was predicted as described in Annex IV and as listed in Tables 6 and 7.

28. The uncontrolled emission of pollutants was calculated from the fuel consumption and the emission factors discussed in Annex V and listed in Tables 15, 16, 17, and 18.

29. The emission levels which would result from applying controls to limit potential emissions for 1980 to about the level estimated for 1970 are shown in Table 5. Results of a similar exercise limiting potential emissions for 1980 emissions to 1960 levels are shown in Table 2.

30. For the control of potential SO_x emissions for 1980 to the estimated 1970 level, the control technology was assumed available as follows.

- (a) Increased mining of low sulfur coal (0.7 percent S average) to the extent that it comprises 28 percent of the total coal production in 1980 for fuel usage. Approximately 35 percent of this will come from the large reserves of low sulfur coal in the western United States, and 65 percent from the low sulfur reserves in the eastern United States.
- (b) Mechanically deep clean approximately 14 percent of the total coal usage to less than 1 percent sulfur content. (0.7 percent S average)
- (c) Install limestone flue gas scrubbers on 25 percent of the power station capacity using high sulfur coal. This is equivalent to scrubbing the flue gas produced from about 14.6 percent of all coal burned. The remaining 75 percent of the high sulfur coal-fired power stations emit their SO_x uncontrolled.
- (d) The remaining about 43.8 percent of all coal used in 1980 will be burned in power stations with no control for SO_x emission.
- (e) Desulfurize all residual fuel oil to be used in 1980 to 0.87 percent sulfur content as discussed in Annex VI.
- (f) There will be 150 new hydrotreating plants installed to meet the total capacity demands of heavy oil which is above the projected demands for light oil.

TABLE 6
UNITED STATES FOSSIL
FUEL CONSUMPTION
1980

	POWER STATION	COKE OVEN	OIL REFINERY	OIL PRODUCT.	IRON & STEEL	CEMENT	OTHER	DOMEST. & COMC'L.
NATURAL GAS	5.186×10^{12} ft. 3	1.09×10^9 ft. 3	$1362. \times 10^9$ ft. 3	$992. \times 10^9$ ft. 3	689.5×10^9 ft. 3	283.1×10^9 ft. 3	21.18×10^{12} ft. 3	5.94×10^{12} ft. 3
MANUFACTURED GAS	106.9×10^9 ft. 3	$386. \times 10^9$ ft. 3			1.225×10^{12} ft. 3		27.6×10^9 ft. 3	13.8×10^9 ft. 3
BLAST FURNACE GAS		640×10^9 ft. 3			5.40×10^{12} ft. 3			
REFINERY GAS								
L.P.G.								
HEAVY FUEL OIL	708×10^6 Bbls.		33.9×10^6 Bbls.		7.71×10^6 Bbls.	8.06×10^6 Bbls.	126.5×10^6 Bbls.	288.6×10^6 Bbls.
FUEL OIL	35.2×10^6 Bbls.		19.05×10^6 Bbls.		33.1×10^6 Bbls.		47.0×10^6 Bbls.	682.0×10^6 Bbls.
BROWN COAL	10.3×10^6 Tons							
HARD COAL	$682. \times 10^6$ Tons				9.0×10^6 Tons	13.28×10^6 Tons	158.3×10^6 Tons	9.92×10^6 Tons
COKE	5.7×10^6 Tons							

TABLE 7
CONSUMPTION OF FUEL
WITH UNCONTROLLED FLUE GAS EMISSION
(DERIVED FROM TABLE 6 DATA)

Regional Group - United States

Sectors	Type of Fuel	Fuel Units	Fuel Rate	NO _x Millions of Metric Tons	SO ₂ Millions of Metric Tons	Particulate Millions of Metric Tons	Fuel Rate Million Metric Tons Oil equivalent
Public power stations	Natural gas	Total	1,362.5 x 10 ¹²	0.798	0.002	0.015	129.5
	Manufactured gas	"	14.76 x 10 ¹²	0.010	0.069	0.001	1.403
	Light fuel oil	thousand metric tons	4,436	0.072	0.032	0.006	4,436
	Heavy fuel oil	"	106,500	1.415	5.504	0.117	106.5
	Hard coal	"	384,300	6.185	31.750	58.880	384.3
Blast furnace gas and B.K.B. not applicable	Brown coal	"	4,000	0.094	0.178	0.889	4.0
	Coke	"	3,810	0.032	0.099	0.493	3.81
	Total			8.626	37.634	60.421	633.949
Refineries	Natural gas	Total	618. x 10 ¹²	1.445	0.001	0.019	58.75
	Light fuel oil	"	2,400	0.025	0.015	0.072	2.40
	Heavy fuel oil	"	5,100	0.440	0.263	0.013	5.10
Coke-ovens	Total			1.910	0.279	0.104	66.25
	Blast furnace gas	Total	15.26 x 10 ¹²	neg.	0.006	0.005	1.45
	Manufactured gas	"	52.35 x 10 ¹²	0.019	0.245	0.004	5.07
Coke not consumed as a fuel	Natural gas	Total	0.28 x 10 ¹²	neg.	neg.	neg.	0.027
	Total			0.019	0.251	0.009	6.547
Iron and steel	Natural gas	Total	180.8 x 10 ¹²	0.065	neg.	0.006	17.19
	Manufactured gas	"	169.0 x 10 ¹²	0.062	0.789	0.010	16.07
	Blast furnace gas	"	128.9 x 10 ¹²	0.049	neg.	0.044	12.25
	Heavy fuel-oil	thousand metric tons	1,160	0.011	0.060	0.003	1.16
	Light fuel oil	"	4,173	0.045	0.026	neg.	4.173
Coke not consumed as a fuel	Hard coal	"	5,070	0.082	0.417	0.650	5.07
	L.P.G.	"	41	neg.	neg.	neg.	0.041
	Total			0.314	1.292	0.693	55.956
Other industries	Natural gas	Total	5,640. x 10 ¹²	2.078	0.006	0.172	536.0
	Manufactured gas	"	3.79 x 10 ¹²	neg.	0.018	neg.	0.36
	Light fuel oil	thousand metric tons	6,550	0.064	0.038	0.019	6.55
	Heavy fuel oil	"	20,250	0.183	1.043	0.051	20.25
	Hard coal	"	89,800	1.543	7.99	12.05	89.8
Blast furnace gas, brown coal and B.K.B. not applicable	Total			-	-	-	-
	Total			3.868	9.095	12.291	652.96
Domestic and others	Natural gas	Total	1,558. x 10 ¹²	0.200	0.002	0.051	148.20
	Manufactured gas	"	1.89 x 10 ¹²	neg.	0.009	neg.	0.18
	Light fuel oil	thousand metric tons	43,420	0.546	0.549	0.130	95.0
	Heavy fuel oil	"	86,000	0.230	2.231	0.055	86.0
	Hard coal	"	5,590	0.036	0.463	0.090	5.59
Blast furnace gas, B.K.B. patent fuel, coke and brown coal not applicable	Total			-	-	-	-
	Total			1.012	3.254	0.326	334.97
	Total			15.749	51.805	73.844	1750.63
GRAND TOTAL							17

n.a. = data not available
neg. = less than 0.001

- (g) All coal burning power stations not equipped with limestone flue gas scrubbers are assumed to be equipped with electrostatic precipitators operating at 90 percent particulate removal efficiency on a continuous basis.

31. The calculated emissions, incorporating the above controls, are listed in Table 8.

32. For control of reduction of 1980 emissions to the 1960 level, the technological requirements are:

- (a) Increased mining of low sulfur coal (0.7 percent S) to the extent that it comprises 28 percent of the total coal production in 1980. Approximately 35 percent of this will come from the large reserves of low sulfur coal in the western United States, and 65 percent from the low sulfur reserves in the eastern United States.
- (b) Mechanically deep clean approximately 14 percent of the total coal usage to less than 1 percent sulfur content.
- (c) Install limestone flue gas scrubbers on 75 percent of the power stations using high sulfur coal. This is equivalent to scrubbing the flue gas from 44 percent of all coal burned.
- (d) The remaining 14 percent of all coal will be burned in power stations, uncontrolled for SO_x .
- (e) Desulfurize all residual fuel oil to 0.87 percent sulfur content as discussed in Annex VI.
- (f) All coal burning power stations not equipped with limestone flue gas scrubbers are assumed to be equipped with electrostatic precipitators operating at 90 percent particulate removal efficiency on a continuous basis.

33. The calculated emissions, incorporating these controls, are listed in Table 9.

34. NO_x is controlled for both the above cases utilizing combustion control by flue gas recirculation and low excess air to the maximum extent. In addition, NO_x is removed together with SO_x in the limestone scrubbing. The difference between 1970 and 1960 levels of NO_x removal is solely due to more limestone scrubbing application in the control to 1960 level.

TABLE 8
CONSUMPTION OF FUEL
WITH FLUE GAS EMISSIONS CONTROLLED TO 1960 LEVEL
(DERIVED FROM TABLE 6 DATA)

Regional Group - United States

Sectors	Type of Fuel	Fuel Units	Fuel Rate	NO _x Millions of Metric Tons	SO _x Millions of Metric Tons	Particulate Millions of Metric Tons	Fuel Rate Million Metric Tons Oil equivalent
Public power stations	Natural gas	Total	1,162.5 x 10 ¹²	0.328	0.002	0.035	129.5
	Manufactured gas	"	14.76 x 10 ¹²	0.003	0.009	0.001	1.403
	Light fuel oil	thousand metric tons	4,436.	0.028	0.032	0.005	4.436
	Heavy fuel oil	"	106,500.	0.566	1.850	0.108	106.5
	Hard coal	"	384,300.	2.974	20.960	4.891	384.3
Blast furnace gas and B.K.B. not applicable	Brown coal	"	4,000.	0.047	0.178	0.009	4.0
	Coke	"	3,810.	0.026	0.098	0.049	3.81
	Total		-	3.972	23.189	5.178	633.949
Refineries	Natural gas	Total	618.0 x 10 ¹²	1.445	neg.	0.019	58.75
	Light fuel oil	thousand metric tons	2,400.	0.025	0.015	0.073	2.40
	Heavy fuel oil	"	5,100.	0.044	0.088	0.013	5.10
Coke-ovens	Total		-	1.514	0.103	0.105	66.25
	Blast furnace gas	Total	15.26 x 10 ¹²	0.006	neg.	0.005	1.45
	Manufactured gas	"	52.35 x 10 ¹²	0.019	0.245	0.004	5.07
Coke not consumed as a fuel	Natural gas	Total	0.28 x 10 ¹²	neg.	0.245	neg.	0.027
	Total		-	0.025	0.245	0.009	6.547
Iron and steel	Natural gas	Total	180.8 x 10 ¹²	0.065	neg.	0.005	17.19
	Manufactured gas	"	169.0 x 10 ¹²	0.062	0.789	0.010	16.07
	Blast furnace gas	thousand metric tons	128.9 x 10 ¹²	0.049	neg.	0.044	12.25
	Heavy fuel oil	"	1,160.	0.011	0.020	0.005	1.16
	Light fuel oil	"	4,173.	0.045	0.026	neg.	4.173
Coke not consumed as a fuel	Hard coal	"	5,070.	0.082	0.108	0.113	5.07
	L.P.G.	"	41.	neg.	neg.	neg.	0.041
	Total		-	0.314	0.943	0.177	55.954
Other industries	Natural gas	Total	5,640. x 10 ¹²	0.540	0.005	0.175	536.0
	Manufactured gas	"	3.79 x 10 ¹²	neg.	0.018	neg.	0.36
	Light fuel oil	thousand metric tons	6,550.	0.016	0.038	0.018	6.55
	Heavy fuel oil	"	20,250.	0.054	0.348	0.048	20.25
	Hard coal	"	89,800.	0.479	2.068	1.551	89.8
Blast furnace gas, brown coal and B.K.B. not applicable	Total		-	1.089	2.477	1.792	652.96
	Natural gas	Total	1,558. x 10 ¹²	0.200	0.002	0.051	148.20
	Manufactured gas	thousand metric tons	43,420.	0.546	0.009	neg.	0.18
Domestic and others	Light fuel oil	"	86,000.	0.230	0.549	0.130	95.0
	Heavy fuel oil	"	5,590.	0.036	0.769	0.055	86.0
	Hard coal	"	-	-	0.120	0.090	5.59
Blast furnace gas, B.K.B., patent fuel, coke and brown coal not applicable	Total		-	1.012	1.429	0.326	334.97
	Total		-	7.936	28.386	7.587	1750.630
	GRAND TOTAL		-	-	-	-	-

n.a. = Data not available
neg. = Less than 0.001

Year 1980
Original OECD Figures and million tons
oil equivalent

TABLE 9
CONSUMPTION OF FUEL
WITH FLUE GAS EMISSIONS CONTROLLED TO 1960 LEVEL
(DERIVED FROM TABLE 6 DATA)

Regional Group - United States

Sectors	Type of Fuel	Fuel Units	Fuel Rate	NO _x Millions of Metric Tons	SO _x Millions of Metric Tons	Particulate Millions of Metric Tons	Fuel Rate Million Metric Tons Oil equivalent
Public power station	Natural gas	Total	1,362.5 x 10 ¹²	0.328	0.002	0.035	129.5
	Manufactured gas	"	14.76 x 10 ¹²	0.003	0.069	0.001	1.403
	Light fuel oil	thousand metric tons	4,436.	0.028	0.032	0.003	4.436
	Heavy fuel oil	"	106,500.	0.566	1.850	0.108	106.5
	Hard coal	"	384,300.	2.749	10.240	2.915	384.3
Blast furnace gas and B.K.B. not applicable	Broom coal	"	4,000.	0.047	0.178	0.089	4.0
	Coke	"	3,810.	0.026	0.098	0.049	3.81
	Total		-	3.747	12.469	3.202	633.949
Refineries	Natural gas	Total	618.0 x 10 ¹²	1.445	neg.	0.019	58.75
	Light fuel oil	"	2,400.	0.025	0.015	0.073	2.40
	Heavy fuel oil	"	5,100.	0.044	0.088	0.013	5.10
Coke-ovens	Total		-	1.514	0.103	0.105	66.25
	Blast furnace gas	Total	15.26 x 10 ¹²	0.006	neg.	0.005	1.45
	Manufactured gas	"	52.35 x 10 ¹²	0.019	0.265	0.004	5.07
Coke not consumed as a fuel	Natural gas	"	0.28 x 10 ¹²	neg.	neg.	neg.	0.027
	Total		-	0.025	0.245	0.009	6.547
Iron and steel	Natural gas	Total	180.8 x 10 ¹²	0.065	neg.	0.005	17.19
	Manufactured gas	"	169.0 x 10 ¹²	0.062	0.769	0.010	16.07
	Blast furnace gas	thousand metric tons	128.9 x 10 ¹²	0.045	neg.	0.044	12.25
	Heavy fuel oil	"	1,160.	0.011	0.020	0.005	1.16
	Light fuel oil	"	4,173.	0.046	0.026	neg.	4.173
Coke not consumed as a fuel	Hard coal	"	5,070.	0.082	0.108	0.113	5.07
	L.P.G.	"	41.	neg.	neg.	neg.	0.041
	Total		-	0.315	0.943	0.177	55.954
Other industries	Natural gas	Total	5,640. x 10 ¹²	0.540	0.005	0.175	536.0
	Manufactured gas	"	3.79 x 10 ¹²	neg.	0.018	0.018	0.36
	Light fuel oil	thousand metric tons	6,550.	0.016	0.038	0.018	6.55
	Heavy fuel oil	"	20,250.	0.054	0.348	0.048	20.25
	Hard coal	"	89,800.	0.479	1.068	1.551	89.8
Blast furnace gas, brown coal and B.K.B. not applicable	Total		-	1.089	2.477	1.792	652.96
	Natural gas	Total	1,558. x 10 ¹²	0.200	0.002	0.051	144.20
	Manufactured gas	"	1.89 x 10 ¹²	neg.	0.009	neg.	0.18
Domestic and others	Light fuel oil	thousand metric tons	95,000.	0.546	0.549	0.130	95.0
	Heavy fuel oil	"	86,000.	0.230	0.748	0.055	86.0
	Hard coal	"	5,590.	0.036	0.120	0.080	5.59
Blast furnace gas, B.K.B., patent fuel, coke and brown coal not applicable	Total		-	1.012	1.428	0.326	334.97
	Total		-	7.702	17.665	5.611	1750.630
GRAND TOTAL							20

n.a. = Data not available
neg. = Less than 0.001

CHAPTER V

BASIS FOR COSTING OF POLLUTION CONTROL IN 1980

34. The pollution abatement strategies outlined in Chapters III and IV and discussed in Annexes VI, VII and VIII were selected after consideration of ways that pollution control might be accomplished at minimum cost using methods which are expected to be commercially available by 1980. Where no presently proven technology was available the most promising method under development was considered and probable costs were assumed. It must be borne in mind that many technical problems remain to be worked out (see Annex XIII and that the costs on these are highly uncertain at this time.

35. All costs are calculated on 1970 prices.

36. The costs which have been developed are considered reasonable order-of-magnitude estimates useful for demonstrating the magnitude of the cost to be expected for control of pollution from combustion. It is impossible to evaluate the effect of many economic factors which can strongly affect the ultimate cost of control, e.g., the assumed application of limestone scrubbing would require doubling of limestone production within eight years. It seems certain that prices will escalate. Also, the capital cost estimates for application of limestone scrubbing are considered very optimistic in light of latest results from development programs. Many other factors could be cited to show that the costs as developed will prove to be very low for the level of control which was assumed.

37. The cost estimated for particulate control is the cost for application of control equipment that would be expected if past and current trends in increased rates of application of control technology continue. The cost for all new equipment to be installed in the 1960-1980 period is included. The cost for equipment installed prior to 1960 is excluded even though their contribution is included for the total amount of particulate collected.

38. Nitrogen oxide emission control is assumed to be achieved principally through combustion control (see Annex XI). There is additional 20 percent NO_x reduction due to flue gas scrubbing for SO_2 control as discussed in Annexes VIII-4 and XIII-5, but no costs are assigned because this benefit is an integral part of SO_x reduction by scrubbing, for which costs are assigned. The total investment is estimated to be $\$2.8 \times 10^9$ with an annual operating cost of \$580 million.

39. The sulfur oxide reduction is assumed to come from four techniques: Hydrotreating heavy fuel oil to an average of 0.87 percent sulfur (the equivalent of 0.54 percent sulfur coal), opening new low sulfur coal mines in both the eastern part and the western part of the United States, cleaning eastern coal down to 0.7 weight percent sulfur, and using limestone scrubbing on some coal-burning furnaces to get the total SO_x emissions down to desired levels. The two cases for which costs are developed assume the reduction of projected 1980 emissions to the 1970 level, and the reduction of the 1980 projected emissions to the 1960 level.

40. Capital costs for control to the 1970 level of emissions are estimated to be almost $\$12.7 \times 10^9$, as shown in Table 10. The corresponding operating costs are shown in Table 12.

41. Capital costs for controlling to the 1960 level of emissions are estimated to be $\$13.5 \times 10^9$, as shown in Table 11. The corresponding operating costs are shown in Table 13.

42. The foregoing tables show that cleaning of heavy fuel oil is a high cost item compared to scrubbing flue gas stacks. However, it is not practicable to attempt to substitute one for the other. The heavy oil is burned in hundreds of thousands of small units. The cost of installing scrubbers in these would be prohibitive, and the problem of disposing of the waste sludge would be almost impossible to solve (see Annex XIII). Furthermore, hydrotreating is commercially available, and limestone scrubbing is in the development status.

43. These tables assume the logical course of events where regulations imposed to reduce pollutants will cause the most workable systems to be installed first. As the problem continues and as costs rise, other abatement techniques will be developed to lower costs.

44. It should be noted that no attempt was made to estimate the cost to fuel users for switching to low sulfur coal or gas. Nor was any cost estimated for items such as additional transportation or the cost of opening mines included, consequently, the costs estimated according to O.E.C.D. guidelines should not be taken to represent total national costs.

TABLE 10
ESTIMATED INVESTMENT AFFECTING COSTS
OF ABATEMENT STRATEGY IN THE UNITED STATES
FOR CONTROL OF 1980 POLLUTANT EMISSIONS TO 1970 LEVEL

Control	Investments (a)
Particulate emissions	\$ 1,330,000,000
NO _x emissions	
Power stations	826,000,000
Other industries	1,998,000,000
SO _x emissions	
Flue gas scrubbing	428,000,000
Fuel oil desulfurization	7,730,000,000
Coal cleaning	<u>420,000,000</u>
Total	\$12,732,000,000

(a) Costs in 1970 dollars

TABLE 11
ESTIMATED INVESTMENT AFFECTING COSTS
OF ABATEMENT STRATEGY IN THE UNITED STATES
FOR CONTROL OF 1980 POLLUTANT EMISSIONS TO 1960 LEVEL

Control	Investments (a)
Particulate emissions	\$ 720,000,000
NO _x emissions	
Power stations	826,000,000
Other industries	1,998,000,000
SO _x emissions	
Flue gas scrubbing	1,790,000,000
Fuel oil desulfurization	7,730,000,000
Coal cleaning	<u>420,000,000</u>
Total	\$13,484,000,000

(a) Costs in 1970 dollars

TABLE 12
ESTIMATED YEARLY OPERATING COSTS
FOR REDUCING 1980 AIR POLLUTANTS
TO 1970 LEVELS IN THE UNITED STATES

Control	Operating Costs (a)
Particulate emissions	\$ 220,000,000
NO _x emissions	
Power stations	213,000,000
Other industries	366,000,000
SO _x emissions	
Flue gas cleaning	118,000,000
Sludge hauling	72,000,000
Fuel oil desulfurization	1,437,000,000
Coal cleaning	<u>87,000,000</u>
Total	\$2,813,000,000

(a) Costs in 1970 dollars

TABLE 13
ESTIMATED YEARLY OPERATING COSTS
FOR REDUCING 1980 AIR POLLUTANTS
TO 1960 LEVELS IN THE UNITED STATES

Control	Operating Costs (a)
Particulate emissions	\$ 118,000,000
NO _x emissions	
Power stations	213,000,000
Other industries	366,000,000
SO _x emissions	
Flue gas cleaning	396,000,000
Sludge hauling	240,000,000
Fuel oil desulfurization	1,437,000,000
Coal cleaning	<u>87,000,000</u>
Total	\$2,857,000,000

(a) Costs in 1970 dollars

ANNEX I

LIST OF PUBLICATIONS AND SOURCE MATERIAL
REFERRED TO IN THIS REPORT

1. "Minerals Yearbook 1961", Bureau of Mines Publication.
2. "Minerals Yearbook 1968", Bureau of Mines Publication.
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ANNEX II

DESCRIPTION OF FOSSIL FUELS USED IN THE UNITED STATES

1. Data have been assembled to show the rates at which fossil fuels were consumed in stationary users in the United States in 1960 and 1970 and projections for the expected use of fossil fuels in 1980. The breakdown of these rates has been along the pattern as set out in "A Report on Air Pollution from Fuel Combustion in Stationary Sources as a Guideline for National Reporting" for the O.E.C.D.
2. Six sectors of stationary sources have been established:
 1. Power stations
 2. Refineries
 3. Coke ovens
 4. Iron and steel
 5. Other industries
 6. Domestic and commercial
3. The fossil fuels consumed in these six sectors by O.E.C.D. identification, are as follows:
 1. Natural gas
 2. Manufactured gas
 3. Blast furnace gas
 4. Refinery gas
 5. Fuel oils
 6. L. P. Gas

7. Patent fuel
 8. Brown coal
 9. Hard coal
 10. Coke
 11. B. K. B.
4. Since the fuel categories in the United States do not exactly fit the categories suggested by O.E.C.D., some adjustments had to be made. The following table details the fuels used in this country and the O.E.C.D. designation to which it compares. For purposes of the O.E.C.D. report, all fuel is reported as metric tons of heavy oil with 41.8×10^{12} Btu per million metric ton.

<u>U. S. FUEL</u>	<u>O.E.C.D. EQUIVALENT</u>	<u>U. S. UNITS</u>	<u>HEAT VALUE BTU/UNIT</u>	<u>WEIGHT % S</u>
Natural gas	Natural gas	Standard cu.ft.	1,045	
Coke oven gas	Manufactured gas	Standard cu.ft.	550	
Blast furnace gas	Blast furnace gas	Standard cu.ft.	95	
Natural gas	Refinery gas	Standard cu.ft.	1,045	
Light fuel oil	Fuel oil	Barrel	5,827,000	0.30
Heavy fuel oil	Fuel oil or heavy fuel	Barrel	6,300,000	2.60 avg.
Coal tar	Heavy fuel	Barrel	6,300,000	2.60
L. P. G.	L. P. G.	Gallon	95,500	
Lignite	Brown Coal	Ton	16,600,000	1.00
Bituminous Coal	Hard coal	Ton	23,600,000	2.70 avg.

5. Wood, bark, municipal refuse, process wastes and the like have not been included among the fuels in this report which deals only with fossil fuels.

ANNEX III

DESCRIPTION OF THE INDUSTRY SECTORS

1. Power Stations - Power stations have been assumed for this report to include fossil-fuel-fired stationary electric generating installations, including those of public utilities, municipal and government utilities. It does not include the electric generating facilities which have been included as part of industrial and commercial operations associated with other industry sectors specified by O.E.C.D. guidelines. In addition, this category does include internal combustion engine and gas turbine generators which are employed to generate electricity.
2. Coke Ovens - Approximately 90 percent of the coke ovens are an integrated part of the iron and steel industry in the United States. By 1968 almost 100 percent of the coke was made in slot ovens and most of those were underfired (Reference 2). Because of this relationship, coke oven gases and blast furnace gases are used when available to supply the heat for making coke; where such fuels are not available, natural gas is used.
3. Further, the petroleum industry has become the source of many chemicals which would otherwise come from coking coal. This has also contributed to the coking industry being incorporated with iron and steel leaving only a small quantity of coke to be burned as fuel in boilers.
4. Approximately 36 percent of the coke oven gas is consumed in the coking ovens, the rest is sold. Only about 9 percent finds its way into power stations or gas mains for burning by "others". This is essentially the only manufactured gas used in the United States.
5. Refineries - The sector called refineries has been defined to include the United States oil refineries, oil fields (or wells), gas fields (or wells), gas condensate plants, and gas pipeline transmission. By and large, these industries run on natural gas with light and heavy oils as supplemental fuels.
6. A good portion of the fuel is used to generate heat in process boilers and direct-fired heaters. Additional amounts are burned in internal combustion engines and gas turbines to generate mechanical or electrical power.

7. Significant quantities of fuel are consumed by the refinery processes (hydrogen generation and ethylene generation, for example) and these quantities are separated out since they do not directly contribute to air pollution.

8. The movement of natural gas from the fields, through the condensate plants and the cross-country pipelines, is powered by the energy obtained from burning natural gas in internal combustion engines and gas turbines. This fuel usage is added in with the uses for refineries proper.

9. Iron and Steel - This sector is taken to be industry which makes iron and steel from iron ore and scrap steel and includes the integration of products for sale such as sheets and structural shapes. The fabrication of these forms into products for resale as finished objects is done by the sector "other" industries.

10. Fossil fuels are consumed as such in high temperature heating by direct firing, in building and process heat, in the generation of steam for heat and electricity. The quantities of coke consumed by ore reduction in furnaces is not considered fuel combustion for purposes of this report because the pollutants in the coke, ash and sulfur compounds leave the plant in the slag, not in the air.

11. Other Industries - Table 14 lists some of the major industries included in the "other" sector. The complexity of this category is discernable by noting that in 1960 only 30 percent of the fuel used by other industries was accounted for by this table, which shows large volume gas sales by utilities.

12. The total marketed fuels, such as natural gas and coal, are available for 1960 and 1970. The fuels used by the individual sectors "power stations", "refineries", "coke ovens", "iron and steel", and "domestic and commercial" are also available. By subtracting these from the total national fuel, the amounts used by "other" was determined. No data sources are available which permit adding individual uses and coming up with an accounting for the 70 percent not accounted for in Table 14.

13. After reviewing the list, it was decided to consider that all the fuels used in the "other" sector were burned for heat value and this basic use is in boilers and furnaces. While this may be in error, it was deemed

reasonable since this procedure separated process pollutants from fossil fuel pollutants.

14. Domestic and Commercial - The use of fuels in this sector is assumed to be for space and building heat and consumed in furnaces and boilers. The statistics are essentially government statistics from the Bureau of Mines yearbooks which listed the fuels actually sold or used by this sector.

TABLE 14
LARGE VOLUME NATURAL GAS UTILITY SALES
TO OTHER INDUSTRY SECTOR

	1960	1965
	Cu. Ft.*	Cu. Ft.*
Agriculture, forestry	10.27 x 10 ⁹	11.50 x 10 ⁹
Other mining	42.82	66.90
Food and kindred products	160.70	232.20
Textile, clothing, fabrics	21.60	41.8
Furniture and wood products	22.10	50.0
Paper and allied products	185.0	256.0
Carbon black	14.35	40.2
Chemicals	497.0	617.0
Rubber products	16.0	37.20
Glass products	138.40	177.0
Clay products	162.40	142.1
Cement	162.5	175.7
Stone products	29.4	65.10
Transportation equipment	62.25	106.40
Fabricated machinery	106.0	259.0
Ordinance	13.5	20.30
Other manufacturing	32.4	60.50
	1,676.69	2,139.90

* Data converted to cubic feet from Therms as reported in "Gas Facts 1966" using natural gas at 1045 Btu per cubic foot.

ANNEX IV

BASIS FOR PREDICTING FUEL CONSUMPTION IN 1980

1. To arrive at a fuel usage breakdown for 1980 from which to calculate the pollutant emissions of SO_x , NO_x and particulates, it was necessary to obtain or develop projections to 1980. This was done for each previously discussed sector of stationary users and a fuel breakdown made along the trends established during the past few years. The objective was to project what the fuel use would be and to assume no fuel substitution for abatement.
2. Although it is obvious that SO_x and particulate emissions can be reduced by substitution of a "clean" fuel for a "dirty" one, low sulfur fuel availability is less than the projected uses by 1980 so that such substitution is only a theoretical solution. The projections were made upon the most recent equipment and fuel patterns since it seems reasonable to suppose that these trends will continue rather than to suppose that entirely new and different patterns will emerge and become dominant in the next nine years.
3. 1980 Power Stations - It is projected that in 1980 there will be 3.325×10^{12} kwh of electricity generated (Reference 4). Of this, 2.392×10^{12} kwh will be developed from fossil fuels. The balance will be supplied by hydroelectric and nuclear power plants (References 6, 27).
4. Fossil fuel for the 2.392×10^{12} kwh will be basically coal, oil and natural gas with coke oven gas, blast furnace gas, lignite and coke also used in minor amounts. Coke and lignite projections were arrived at by assuming the growth rates of each would be the same as in the past five years. Coke oven gas and blast furnace gas were assumed to be that left over from the steel and coke oven uses. Natural gas usage is assumed to have a growth of about 4.2 percent per year. Oil projections were calculated at 8.8 percent per year or about one-half those of References 13 and 39.
5. All of these fuels were converted to kwh equivalents and subtracted from the projected electricity needs and the balance assumed to be supplied by coal. As a cross-correlation all other uses of gas were added and their sum subtracted from the total natural gas projected to be available in 1980. Since increased gas supplies will come as a result of much

higher prices, it is assumed that this fuel will be less attractive to the utility industry and that long-term coal supplies will fill the gap of needed fuel. Furthermore, natural gas is a nonpolluting fuel from the standpoint of SO_x and particulate emissions and the cost of add-on abatement steps will not be practicable for the small and intermediate stationary users whereas a higher price for the clean fuel might be. High sulfur high ash will be lower cost and therefore used by large consumers who can justify add-on abatement devices.

6. This rationale for projecting fuels for the power stations depends upon the competition from the "other" industries sector and the "domestic and commercial" users for fuel. They have been and will probably continue to be larger fuel users than the utility sector.

7. 1980 Oil Refineries - The production of oil and gas has been projected separately (References 23, 24), and this projection was used to calculate the use of fuel to refine oil and natural gas for markets on a unit consumption basis. The unit consumptions of 1970 have been assumed to be valid for 1980. The important fuels are natural gas, light fuel oil and residual fuel oil with the others of minimal significance.

8. Natural gas is a regulated fuel in the United States. However, as the price is allowed to rise the incentives to drill more wells will make more available. Therefore, we have assumed a growth at the same annual rate that this industry has experienced in the last ten years. It makes little difference whether the gas is imported or supplied from fields in the United States. The fuel used to refine and distribute the products will go up in proportion to the total gas.

9. 1980 Coke Ovens - The production of coke and its by-products is closely tied to the production of steel. Predictions have been made for 1980 (Reference 8) and these were used to calculate the consumptions of coal and natural gas. The utilization of oven gas and blast furnace gas in 1970 was assumed to hold for 1980. This applied to the amount of coke oven gas that was sent into other users as well.

10. 1980 "Other" - From the data of Table 4 a growth rate of 4.90 percent per year is developed. From Tables 1 and 3 a growth rate of 3.92 percent is calculated. Since the nature of the "other" sector is so varied it is difficult to accurately determine its growth rate. For the sake of this study a rate of approximately 4.0 percent per year was used.

11. It is worth noting the large amounts of fuels consumed by "other". Small percentage influences on this sector could greatly offset the national total.

ANNEX V

FACTORS FOR CALCULATING EMISSION RATES OF POLLUTANTS

1. An emission factor is the quantity of a particular pollutant emitted from a certain process, such as combustion or industrial production, for a given quantity of fuel or production, e.g., pounds of SO₂ per ton of coal burned. For this report a deliberate effort has been made to isolate the fuel pollutants from any process emanating pollutants. Consequently, any practicable substitution of fuels could be made freely. It is recognized in some cases the process pollutants are much greater than those from the fossil fuel but these are outside the scope of this report.
2. Once an emission factor has been determined for a given process, the total quantity of pollutant emitted from processes of the same type over a certain time period can be readily computed by multiplying this factor by the units of fuel burned or production during the period.
3. The latest available data on emission factors is contained in Reference 5. Most of the required emission factors for SO₂, NO₂ and particulates were taken from this book with the following exceptions:
 - Coke oven gas, SO₂ - Reference 8.
 - Coke oven gas, NO₂ and particulates, used same factors as for natural gas.
 - Blast furnace gas, SO₂, assumed negligible.
 - Blast furnace gas, NO₂ and particulates, assumed same as for natural gas.
 - Refineries, NO₂ - Reference 11.
4. Reference 5 cited above includes accuracy ratings for the emission factors on each type of fuel. These consist of a letter designation A, B, C, D, or E, with the following definitions:

- A - Excellent, based on field measurement of a large number of sources.
- B - Above average, based on a limited amount of field measurements.
- C - Average.
- D - Below average.
- E - Poor.

These rating designations, where given, are included in the tables of emission factors as a letter following the fuel type.

5. It must be remembered that emission factors are averages and can vary widely for particular installations, depending on type, size, operating conditions, etc. For instance, the NO₂ emission from the combustion of coal is believed to be a function of temperature and excess air, affecting the amount of nitrogen oxidized to nitric oxide. However, tests have indicated (Reference 32) that a good deal of the NO₂ is formed from nitrogen compounds in the coal. This could have an effect of undetermined magnitude on the control of NO₂ from coal combustion.

6. The emission factors for each type of fuel of interest are listed in Tables 15, 16, 17, and 18.

7. One fuel that has received special treatment is refinery fuel. This fuel is primarily natural gas with varying contents of hydrogen sulfide and ammonia. Due to the wide range of content, it was treated as natural gas, although this is known to be in error.

TABLE 15
EMISSION FACTORS, POWER STATIONS

	SO ₂	NO ₂	Particulates
NATURAL GAS (B)			
BOILERS	.6#/Million Ft. ³	390#/Million Ft. ³	15#/Million Ft. ³
GAS TURBINES	.6#/Million Ft. ³	200#/Million Ft. ³	15#/Million Ft. ³
COKE OVEN GAS	Equiv. to 1.6% S Coal on Btu Basis	Same as Natural Gas on Btu Basis	Same as Natural Gas
FUEL OIL (A)	157 x % S #/1000 Gal.	105#/1000 Gal.	8#/1000 Gal.
RESIDUAL OIL (A)	157 x % S #/1000 Gal.	105#/1000 Gal.	8#/1000 Gal.
BROWN COAL	Same as Hard Coal	Same as Hard Coal	Same as Hard Coal
HARD COAL (A)	38 x % S #/Ton	20#/Ton	16 x % Ash #/Ton
COKE	Same as Hard Coal	Same as Hard Coal	Same as Hard Coal

TABLE 16
EMISSION FACTORS, INDUSTRIAL BOILERS

	SO ₂	NO ₂	Particulates
NATURAL GAS (B)	.6#/Million Ft. ³	214#/Million Ft. ³	18#/Million Ft. ³
COKE OVEN GAS	Equiv. to 1.6% S Coal on Btu Basis	Same as Natural Gas on Btu Basis	Same as Natural Gas
BLAST FURN. GAS	NIL	Same as Natural Gas on Btu Basis	Same as Natural Gas
LPG (C)	$\frac{.3 \times \text{Gr. of S per 100 Ft.}^3}{1000 \text{ Gal.}}$	40#/1000 Gal.	6#/1000 Gal.
FUEL OIL (A)	142 x % S #/1000 Gal.	72#/1000 Gal.	15-23#/1000 Gal.
RESIDUAL OIL (A)	157 x % S #/1000 Gal.	72#/1000 Gal.	15-23#/1000 Gal.
HARD COAL (B)	38 x % S #/1000 Ton	20#/Ton	13 x % Ash #/Ton

TABLE 17
EMISSION FACTORS, DOMESTIC AND COMMERCIAL

	SO ₂	NO ₂	Particulates
NATURAL GAS (B)	.6#/Million Ft. ³	50-100#/Million Ft. ³	19#/Million Ft. ³
COKE OVEN GAS	Equiv. to 1.6% S Coal on Btu Basis	Same as Natural Gas on Btu Basis	Same as Natural Gas
LPG (C)	$\frac{.3 \times \text{Gr. of S per 100 Ft.}^3}{1000 \text{ Gal.}}$	20-35#/1000 Gal.	6#/1000 Gal.
FUEL OIL (A)	142 x % S #/1000 Gal.	12-72#/1000 Gal.	10#/1000 Gal.
RESIDUAL OIL (A)	157 x % S #/1000 Gal.	12-72#/1000 Gal.	10#/1000 Gal.
HARD COAL (A)	38 x % S #/Ton	8#/Ton	20#/Ton

TABLE 18
EMISSION FACTOR FOR NO_x, REFINERIES

Oil and Gas Production		
Natural Gas		
Heaters and Boilers		.2#/1000 Ft. ³
Gas Engines		.77#/1000 Ft. ³
Pipelines		
Natural Gas		
Gas Engines		7.3#/1000 Ft. ³
Gas Turbines		.2#/1000 Ft. ³
Refining		
Natural Gas		
Heaters and Boilers		.21#/1000 Ft. ³
Gas Engines		4.35#/1000 Ft. ³
Gas Turbines		.2#/1000 Ft. ³
Oil		
Heaters and Boilers		2.8#/Barrel

ANNEX VI

FUEL CLEANING

1. Fuel cleaning for 1980 in the United States is restricted to hydrotreating residual or heavy fuel and deep cleaning of high sulfur coal to remove primarily sulfur or sulfur compounds.
2. Desulfurization of oil - Current trends in legislation are to restrict sulfur content of heavy oil to less than 1.0 weight percent and in some localities to less than 0.5 weight percent (Reference 41). It is assumed that by 1980 the average of all heavy fuel oil will be 0.87 weight percent, which is equivalent to coal at 0.54 weight percent on a higher heating value (HHV) basis or 0.46 pounds sulfur per million Btu.
3. Variability of oils and of their sulfur content are wide, and it is assumed that the low-sulfur heavy fuel oils will be catalytically hydrogenated in the United States and the resulting product oils blended into the overall stocks for sale. Although some hydrotreated oils will probably be imported, the costs, blending stocks, and market patterns favor domestic production using imported oils.
4. The presence of metals such as nickel and vanadium in hydro-treated feedstock contributes to short catalyst life by poisoning the catalyst (Reference 28). Heavy or residual oils are high in coke precursors which break down in the reactor bed and deposit coke on the catalyst, resulting in further poisoning. Both of these harmful constituents of oil are greatly reduced by using fractionated oils. The heavy, nonvolatile, poisonous materials stay with the bottoms oil and yield oils which may be hydrotreated with greater ease and longer catalyst life.
5. Refining trends in the United States are to produce less residual or heavy fuel oil per barrel of crude and less heavy fuel oil in total. To supply the increased demand for heavy fuel oil in 1980, the projection has been made that a major portion of the oil supply will have to be imported.

6. 1971 capacity for hydrorefined oils is 195,800,000 barrels per year, and most of this consists of light fuel oils. To achieve the total capacity of 1,173,000,000 barrels per year of heavy oil, hydrotreating capacity above the light oil production will require an intensive construction program. Building 150 new hydrotreating plants with a capacity of 31,500 B.P.S.D. appears to be the limit of practicability by 1980.

7. Although light oil hydrotreating is widely practiced in the United States, the hydrotreating of heavy oils and residuals has not been widely practiced. To date only three processes have been operated on a large scale (References 26, 27, 28).

8. A by-product of hydrogen treating is an off-gas stream containing hydrogen sulfide and ammonia mixed with light ends of hydrogen, methane and ethane. By alkaline scrubbing, the hydrogen sulfide can be recovered from this off-gas. Hydrogen sulfide can be converted to sulfuric acid or to elemental sulfur. It is easier to store and to sell sulfur, so this is usually done. Ammonia is generally burned in the refinery gas stream. This is an unknown NO_x emission which is of minor significance.

9. A second by-product of heavy oil desulfurization is middle distillate or fuel oil. This is of good quality, being low in sulfur and having good combustion properties.

10. This multiproduct nature of hydrotreating creates problems which are best handled by having the hydrotreater as part of a refinery complex. Hydrogen is needed in large quantities, and the most economic source is off-gas from a naphtha reformer which must be integrated into an oil refinery. The additional problems of disposing of waste gas, supplying steam, the needs for tankage and quality control, and finally marketing and distribution, are all common to refinery. However, in 1971 there are only 36 refineries of sufficient size (100,000 B.P.S.D. or over) to absorb such units (Reference 23).

11. Coal cleaning - Mechanical cleaning of coal involves the separation of coal from waste products such as shale, pyrite, and roof-slate by utilizing differences in the physical properties of the materials. The practice of mechanically cleaning coal has existed for many years but, until recently, the purpose has been to remove shale, which is the major impurity. In 1968, approximately 65 percent of the total United States coal production was mechanically cleaned to remove shale and dust.

12. The differences in specific gravity between coal and its impurities form the basis of the conventional coal cleaning processes. The specific gravity of coal is about 1.3, of shale about 2.5, and of pyrite about 5.0.

13. The mechanical removal of pyritic sulfur involves crushing the coal to release the pyrite and then the specific gravity separation of the pyrite from the coal. In many coal beds, the pyrite particles are so small and so intimately mixed with the coal that finer crushing is required than the 3/8 inch to 1-1/2 inch top size used in many conventional coal cleaning plants. As the pyrite particle size becomes smaller, removal becomes more difficult and costly.

14. The principal types of coal cleaning processes are cyclone separation, froth flotation, heavy media separation, jigging, launder-type washers, pneumatic washers, hydraulic tabling, and combinations of these.

15. It is estimated (Reference 9) that 44×10^6 tons of the 1968 coal production for utility use in the Appalachian coal region of the United States was cleanable to a 1 percent sulfur content. This is based on crushing to 3/8 inch sizes. With pulverizing, the cleanable quantity is increased to 60×10^6 tons.

16. The estimated reserves (Reference 9) of coal cleanable to 1 percent sulfur in the Appalachian region are as follows:

	<u>Mine Reserves</u>	<u>Recoverable Reserves</u>
3/8 inch size	880×10^6 tons	$23,000 \times 10^6$ tons

ANNEX VII

ADVANCES IN COMBUSTION TECHNOLOGY

1. Power plant emission of nitrogen oxides will become more and more of a problem in future years. Power plant boilers can produce up to 1000 ppm of NO_x in stack gas emissions.

2. Some techniques for boiler firing have been developed, however, that make reduction to 250 ppm possible today. Further development may make it possible in the future to limit emissions to 100 ppm or even 50 ppm for oil and gas firing (References 25, 40).

3. It has been established that NO is the only nitrogen-oxygen compound that can form, be stable, and exist in significant quantities in the high temperature portions of a utility boiler system (Reference 1). Present methods, therefore, are aimed at minimizing the amount of NO that is formed in the boiler furnace.

4. Present methods with their applicability and limitations are outlined below:

- a. Low Excess Air Combustion. The theory of low excess air combustion predicts a reduction in NO_x emissions by limiting the availability of one reactant, oxygen. Actual operating data are still limited on this type of operation. Low excess air operation may be difficult, if not impossible, to apply to pulverized coal installations.
- b. Burning Equipment Modifications. The principal aim here is to slow the rate at which fuel and air mix. Thus, more heat is removed from the gas before combustion is complete. This results in a lower peak flame temperature of the combustion gases and a reduction in the amount of NO_x that is formed in the furnace. This method has the following drawbacks which may limit its application:
 - (i) Burner turndown is sacrificed.
 - (ii) Combustion process can become unstable.

(iii) Furnace rumble or vibration may become a problem.

(iv) Incomplete combustion may result.

c. Lower Combustion Air Inlet Temperature

(i) This results in lower peak flame temperatures of the combustion gases with the attendant reduction in NO_x formation in the furnace.

(ii) This method is not too good because the reduction in NO_x generation is small and the overall plant thermal efficiency is reduced.

d. Two-stage Combustion. In this process, the amount of air introduced into the primary combustion zone with the fuel is reduced below the theoretical requirement. Then, several feet above the top row of burners, the final combustion air is introduced into the combustion area, and the combustion process is completed. This process is effective in that both peak and average flame temperatures are reduced and thus NO_x formation is reduced (Reference 40). The process also limits the available oxygen for NO_x formation in the first stage and reduces the residence time for NO_x formation at peak flame temperature in the second stage.

e. Flue Gas Recirculation. This process diverts a portion of flue gas back to the furnace combustion chamber. This has the effect of decreasing peak flame temperature and diluting the combustion air and resultant flue gases. NO_x emission is reduced because the flame temperature is lower, because the concentration of oxygen in the combustion gases is reduced, and because the residence time is reduced due to a higher mass flow rate.

5. Combination techniques - By using combinations of the above techniques, such as low excess air firing plus flue gas recirculation, or two-stage combustion plus flue gas recirculation, it is felt that NO_x emissions can be reduced below 100 ppm and may even approach 50 ppm (Reference 40).

However, before these low emission levels can be approached, much additional development work will be required. The control methods discussed above have been applied with measureable success or appear to have application in limiting the NO_x formed in the furnaces of oil and gas-fired boilers. The methods discussed above do not, however, appear to be generally applicable to coal-fired boilers. Thus new developments are required so that NO_x emissions from coal-fired units can be controlled.

ANNEX VIII

FLUE GAS CLEANING

1. An alternative to using clean fuel in a boiler or furnace is to install a stack scrubbing system after the boiler. Several processes have been advanced for this purpose and a few of them have been carried through to pilot plant demonstration (Reference 33). For this study we have concentrated on the one that has the greatest chance of being a commercial success - limestone injection and wet scrubbing.
2. Three main problems must be surmounted on this system:
 - a. How is the fly ash to be handled? The United States Government-sponsored work now underway will determine if it is possible to eliminate the electrostatic precipitators and collect the ash in the scrubber.
 - b. How will the scaling due to CaSO_4 and its hydrates be overcome? It has been reported that adding the stone into a delay tank after absorption helps to reduce this problem.
 - c. How will the tonnages of waste solids be disposed of? Up to now there are no known markets for this material (see Annex XIII).
3. Since this system has four units of commercial size under development, it has been decided to use this system in the control strategy.
4. Pulverized limestone can be injected directly into the boiler. The limestone is calcined and partially reacts with SO_2 in the boiler. The partially sulfated lime, fly ash and most of the remaining sulfur dioxide plus some NO_2 are washed from the flue gas by contact with a recirculated lime slurry. The problem of scale formation and erosion still requires developmental work.
5. Reaction products, mostly calcium sulfite and sulfate, plus fly ash buildup in the aqueous slurry and are removed by settling. The supernatant liquid is returned to the process. The sludge is disposed of

in a settling pond or by transporting, after further concentration, to a landfill site. The treated flue gas is reheated and discharged to the atmosphere.

6. The limestone can also be added directly to the scrubber circuit instead of to the boiler, although this needs to be more fully demonstrated. The scrubbing efficiency is decreased and a greater quantity of limestone is required, but this method is the one considered in this report because the heat requirements of calcining calcium carbonate decrease the boiler efficiency and cause other problems which would not be encountered in an add-on system.

7. From Reference 33, the sludge from all the scrubbing units is estimated to be 347,000,000 tons per year. From Reference 31, it is estimated that 292,000,000 tons of sludge per year are produced. Furthermore, the sludge is a complicated mixture of the carbonates, sulfites, sulfates, nitrites, and nitrates of calcium. The assumption has been made that the sludge will be moved to some disposal site, but the nature and definition of this site will require additional research and development work.

8. The sulfites and nitrites have an appreciable COD and liquid which require converting these anions to sulfates and nitrates. This conversion step has not been included in this report (see Annex XIII).

ANNEX IX

COSTS OF CLEANING COAL

1. Capital costs for typical coal cleaning plants are given in Reference 9 as follows:

- a. Type - Simple plant, coals being prepared are easily cleansable and require a minimum of crushing and preparation.

Size - 500 tons input per hour.

Cost - \$3300 per hourly ton of capacity.

- b. Type - Medium to maximum plants. These coals require crushing to smaller top sizes with maximum effort in preparation of fine coal sizes to obtain maximum pyrite separation.

Size - 500 tons per hour.

Cost - \$8000 - \$14,000 per hourly ton of capacity.

2. In order to provide coal with less than 1 percent sulfur, a high quality plant such as type b. will be required with sizes ranging between 500 and 1400 tons per hour.

3. The yearly requirement of cleaned coal is 118×10^6 tons based on a heating value of 11,800 Btu per pound. For cleaned coal having a 10 percent increase in heating value and a cleaning plant operating 4000 hours per year at 80 percent yield, the total hourly input is:

$$\frac{118 \times 10^6}{4000 \times 0.8} \times \frac{1}{1.1} = 33,500 \text{ tons per hour}$$

Total capital cost would be $(33,500 \times 14,000 = \$470,000,000)$.

4. This program calls for 30 new coal cleaning plants to be built in the next nine years, with an average capacity of 1000 tons per hour which seems to be the technically feasible limit.

5. Another source (Reference 34) gives the capital cost for coal cleaning as \$12 per kw. This is based on a 1000 ton per hour plant with the sulfur content reduced from 2.5 percent to 1 percent, and is independent of plant load factor. For a plant heat rate of 10,300 Btu per kwh, the total electrical output is:

$$118 \times 10^6 \times \frac{2000 \times 11,800}{10,300} = 270 \times 10^9 \text{ kwh}$$

$$\frac{270 \times 10^9}{365 \times 24} = 310 \times 10^6 \text{ kw}$$

On this basis, the capital cost would be $(310 \times 10^6 \times 12 = \$370,000,000)$.

6. Using the average of the capital costs obtained from the two sources gives a total capital cost for coal cleaning plants of \$420,000,000.

7. Operating costs for coal cleaning plants are given in Reference 34 as 0.32 mills per kwh.

$$0.32 \times 270 \times 10^9 \times \frac{1}{1000} = \$87,000,000 \text{ per year}$$

ANNEX X

COST OF DESULFURIZING OIL

1. It is assumed that by 1980 there will be 150 new, integrated hydrogen treating plants constructed in the United States, and each of these will be associated with a major oil refining complex. Each new installation will have a crude distillation system, a reforming plant, a hydrogen purification plant, a hydrogen desulfurization unit, a hydrogen sulfide recovery and elemental sulfur plant, and a production fractionator (Reference 26). The combined facilities will produce low-sulfur, heavy fuel oil at the annual rate of 1,173,000,000 barrels.
2. With anticipated yields of 80 percent heavy oil, each hydrotreating plant will have a capacity of 31,500 B.P.S.D. at 0.88 load factor. The units will be heavy oil treaters of the H-Oil or RDS Isomax type, and sulfur removal is assumed at 75 percent.
3. Hydrogen treating consumes large quantities of hydrogen to satisfy the simultaneous reactions of desulfurization, saturation, and cleavage. A good portion of this hydrogen will be supplied by off-gas from a naphtha reformer. The balance of the hydrogen must be supplied by other off-gas streams from the associated refinery. At an average consumption of 500 standard cubic feet per barrel, each plant will need 16,000,000 standard cubic feet per day. An accompanying light oil treating plant will take an additional 2,000,000 standard cubic feet.
4. By 1980, natural gas will either be too costly or too rare to be considered as a source of hydrogen. Any additional sources will probably be from heavy oil steam reforming which will help dispose of high sulfur stocks.
5. The sulfur removed from the heavy oil feed of each system amounts to 86 long tons of sulfur each day. The average hydrogen sulfide recovery and sulfur plant will be sized for 100 long tons per day.
6. The simultaneous products and the need for ancillary facilities are the reasons the assumption was made that the facilities would be associated with a complete refinery.

7. Investment and operating costs for each of the heavy fuel oil treating units are taken from the recent report by Paradis et al (Reference 26), and scaled by the 0.6 power to the appropriate size ratio.

8. Investment Costs

<u>Unit</u>	<u>Size</u>	<u>Capital Cost</u>
RDS Isomax	31,500 B.P.S.D.	\$10,800,000
Product distillation	32,000 B.P.S.D.	1,800,000
Crude fractionation	71,000 B.P.S.D.	-
Hydrogen plant	18,000,000 scf/d	5,300,000
Reformer	18,000 B.P.S.D.	-
H ₂ S and sulfur plants	100 Lt/d	4,600,000
Light oil hydrotreater	22,000 B.P.S.D.	-
Other		-
		<u>\$22,500,000</u>
Off-site investment		24,300,000
Contingency		<u>4,700,000</u>
Total investment		\$51,500,000

9. Operating Costs

Steam (\$1.60/M lb)	\$ 589,000
Cooling water (\$0.02/M gal)	125,000
Power (\$0.0175/kwh)	745,000
Fuel (\$3.00/bbl)	<u>1,765,000</u>
	\$ 3,224,000
Catalysts and chemicals	\$ 517,000
Labor	200,000
Maintenance	990,000
Overhead	517,000
Taxes and insurance	1,040,000
Contingency	<u>517,000</u>
	\$ 3,781,000
Total operating fixed costs	\$ 7,005,000
Capital depreciation (20 yr str. line)	<u>\$ 2,575,000</u>
Total operating cost	\$ 9,580,000

10. To supply 1,173,000,000 barrels per year of low-sulfur heavy fuel oil will require an additional capital outlay of \$7,730,000,000, and a yearly operating cost of \$1,437,000,000.

ANNEX XI

COSTS OF COMBUSTION CONTROL

1. In order to establish a basis for estimating the cost to control NO_x emissions in 1980, a summary of boiler plant sizes in 1970 was undertaken to establish the average boiler size in 1970. Of 806 surveyed coal-fired boilers installed and operating in 1970, the average size was 105 mw. Of 456 surveyed oil or gas-fired boilers installed and operating in 1970, the average size was 77 mw.

2. For purposes of this cost estimate, we have made the following assumptions:

- a. By 1980, the average size of all boilers, whether coal gas, or oil-fired, will grow to 120 mw.
- b. By 1980, technology will have advanced to where NO_x emission control can be achieved in coal-fired boilers, using methods which are applicable to oil and gas-fired units.

It is projected that by 1980 the installed United States fossil-fueled generating capacity will be approximately 496,000 mw. This will be divided, according to Bartok, et al, 67.7 percent coal-fired and 32.3 percent oil or gas-fired units (Reference 11). Therefore in 1980, there will be 336,000 mw of coal-fired capacity and 160,000 mw of oil or gas-fired capacity.

3. Based upon the above stated average size of 120 mw for all fossil-fueled boilers in 1980, there will then be a total of 2800 coal-fired and 1330 oil or gas-fired boilers operating in 1980.

4. Using the data of Bartok, et al, regarding costs of installing and operating combustion modification controls, the total capital expenditure by 1980 and the operating cost in 1980 can be estimated. Consideration will be limited to the case of a combination of low excess air firing and flue gas recirculation.

The list below summarizes the data taken from Bartok, et al, concerning the costs (Reference 11).

Combustion Modification Costs
Low Excess Air Plus Flue Gas Recirculation
Plant Size - 120 Mw
Load Factor - 4820 Hours Per Year

Fuel	Fixed Costs		Operating Costs		Total Costs Per Year
	Capital Equipment	Capital Charges	Maintenance Supplies and Overhead	Other Operating Costs	
Coal	208	29	44	-17.6	55.4
Gas	183	26	39.6	-8.8	56.8
Oil	183	26	39.6	-35.2	30.4

All costs in \$1000

Thus the capital investment required to install control equipment in coal-fired plants will be $\$208,000 \times 2800$ plants or $\$5.82 \times 10^8$. Likewise, the capital required for oil and gas-fired plants will be $\$183,000 \times 1330$ plants or $\$2.44 \times 10^8$. Thus, the total capital cost involved to install control devices for NO_x emissions from all fossil-fueled plants by 1980 is $\$8.26 \times 10^8$.

5. The annual operating costs for NO_x emission control by combustion modifications in coal-fired plants operating an equivalent of 4820 hours per year is $\$55,400 \times 2800$ plants or $\$1.55 \times 10^8$. Similarly, taking the average from the table, the annual operating costs in oil or gas-fired units will be $\$43,600 \times 1330$ plants or $\$5.8 \times 10^7$.

6. Thus, annual operating costs to control NO_x emissions from fossil-fueled generating plants in 1980 will be $\$2.13 \times 10^8$.

7. Costs for controlling NO_x emissions from industrial boilers are given in Reference 11 as follows:

	<u>Size of Boiler Lb/hr of Steam</u>	<u>Fuel</u>	<u>Capital Cost</u>	<u>Operating Cost Per Hour</u>
a.	27,700	Gas or Oil	\$11,000	\$2,600
b.	144,500	Gas or Oil	\$106,500	\$16,800
c.	36,100	Coal	\$17,200	\$3,840
d.	187,500	Coal	\$140,500	\$22,480

The unit costs based on the above, in dollars per pound of steam per hour, are:

	<u>Unit Capital Cost</u>	<u>Unit Operating Cost</u>
Gas or oil		
a.	\$0.40	\$0.094
b.	\$0.74	\$0.116
Average	\$0.57	\$0.105
Coal		
c.	\$0.48	\$0.106
d.	\$0.75	\$0.120
Average	\$0.62	\$0.113

8. The basis for determining the total steam capacity of industrial boilers is:

Steam pressure	150 psig
Feed water temperature	200F
Boiler efficiency	75 percent

$$\text{Heat input percent} = \frac{1196-168}{.75} = 1370 \text{ Btu per pound of steam}$$

9. The total steam output is calculated as follows:

Fuel usage in metric tons of oil equivalent:

Gas and Oil	555×10^6
Coal	90×10^6

Steam production:

Gas and Oil	$\frac{555 \times 10^6 \times 41.9 \times 10^6}{1370} = 17.0 \times 10^{12} \text{ lb/yr}$
Coal	$\frac{90 \times 10^6 \times 41.9 \times 10^6}{1370} = 2.75 \times 10^{12} \text{ lb/yr}$

The total hourly rate, using a 65 percent load factor is:

Gas and Oil	$\frac{17.0 \times 10^{12}}{8800 \times .65} = 2.98 \times 10^9 \text{ lb/hr}$
Coal	$\frac{2.75 \times 10^{12}}{8800 \times .65} = .48 \times 10^9 \text{ lb/hr}$

10. The costs for NO_x control on industrial boilers are:

Capital Cost:

Gas and Oil	$2.98 \times 10^9 \times .57 = \$1700 \times 10^6$
Coal	$.48 \times 10^9 \times .62 = \frac{\$298 \times 10^6}{\$1998 \times 10^6}$

Operating Cost:

Gas and Oil	$2.98 \times 10^9 \times .105 = \$312 \times 10^6$
Coal	$.48 \times 10^9 \times .113 = \frac{\$54 \times 10^6}{\$366 \times 10^6}$

11. The total costs for NO_x control on power stations and industrial boilers are:

Capital Cost	= \$2,824,000,000
Operating Cost	= \$579,000,000

ANNEX XII

COSTS OF FLUE GAS CLEANING

1. The cost of limestone scrubbing depends on a number of factors, such as sulfur content of the coal, cost of limestone, degree of grinding, power plant size and location, and excess limestone used.

2. The following cost data were obtained from Reference 33:

Basic plant - 200 mw power plant, existing, 3.5 percent S in coal, limestone injection and scrubbing, limestone cost \$2.05 per ton, reheat to 240F, 95 percent SO₂ removal, 99.5 percent dust removal nonrecycle of sluice water.

Capital cost - \$13.05 per kw of capacity.

Operating cost - 0.49 mills per kwh.

3. For differences from the basic plant, the costs are given as follows:

<u>Difference from Basic Plant</u>	<u>Capital Cost \$/kw</u>	<u>Operating Costs Mills/kwh</u>
2 percent S	11.70	0.39
5 percent S	14.30	0.59
Limestone @ \$1/ton		0.44
Limestone @ \$4/ton		0.59
200F reheat	10.52	0.42
170F reheat	9.47	0.40
Sluice water recycled		0.50
Addition of limestone to scrubber circuit	13.80	0.53
500 mw plant	10.85	0.41
1000 mw plant	8.21	0.34
1000 mw plant with addition of limestone to scrubber circuit	8.82	0.37
1000 mw, new, electrostatic precipitator eliminated	6.32	0.29

4. For the purposes of this estimate, the conditions for the basic plant are assumed same as paragraph 2 above, except for the size of installations on new power plants which is assumed to be 300 mw capacity.

5. For control to 1970 level assume scrubbers only on new power plants with an average size of 300 mw. All other conditions are the same as for the basic plant.

	<u>Capital Cost</u> \$/kw	<u>Operating Cost</u> Mils/kwh
200 mw existing	13.05	0.49
1000 mw existing	8.21	0.34
1000 mw new	6.32	0.29

For 200 mw new:

$$\text{Capital cost} = 13.05 \times \frac{6.32}{8.21} = \$10.00/\text{kw}$$

$$\text{Operating cost} = .49 \times \frac{.29}{.34} = .42 \text{ mils/kwh}$$

For 300 mw new:

$$\text{Capital cost} = 10.00 - \frac{1}{8} (10.0 - 6.32) = \$9.50/\text{kw}$$

$$\text{Operating cost} = .42 - \frac{1}{8} (.42 - .29) = 0.40/\text{mils/kwh}$$

$$\text{Coal usage} = 128 \times 10^6 \text{ tons (approximately 20 percent of 1980 coal-fired plants)} \quad \frac{128 \times 10^6 \times 2000 \times 11,800}{10,300} = 294 \times 10^9 \text{ kwh}$$

With 75 percent load factor:

$$\frac{294 \times 10^9}{365 \times .24 \times .75} = 45 \times 10^6 \text{ kw}$$

$$\text{Capital cost} = 45 \times 10^6 \times 9.50 = \$428,000,000$$

$$\text{Operating cost} = 294 \times 10^9 \times \frac{.40}{1000} = \$118,000,000/\text{yr}$$

6. For control to 1960 level assumptions: 40 percent of the scrubbers on new power plants and 60 percent on existing power plants. An average size of 300 mw is used for the new power plants and 200 mw for the existing power plants.

	Capital Cost \$/kw	Operating Cost Mils/kwh
300 mw, new	9.50	0.40
200 mw, existing	13.05	0.49

$$\text{Average capital cost} = .4 \times 9.50 + .6 \times 13.05 = \$11.60/\text{kw}$$

$$\text{Average operating cost} = .4 \times .40 + .6 \times .49 = 0.45 \text{ mils/kwh}$$

Coal usage = 383×10^6 tons (approximately 60 percent of 1980 coal-fired power plants):

$$\frac{383 \times 10^6 \times 2000 \times 11,800}{10,300} = 880 \times 10^9 \text{ kwh}$$

With 65 percent load factor:

$$\frac{880 \times 10^9}{365 \times 24 \times .65} = 154 \times 10^6 \text{ kw}$$

$$\text{Capital cost} = 154 \times 10^6 \times 11.6 = \$1,790,000,000$$

$$\text{Operating cost} = 880 \times 10^9 \times \frac{.45}{1000} = \$396,000,000/\text{yr}$$

7. The prices assumed for limestone are conservative. The impact of a new market for 66,000,000 tons of limestone in the next nine years cannot be determined.

8. The movement of sludge (see Annex VIII-7) will add an additional \$240,000,000 per year if it is hauled an average of 50 miles at a cost of \$0.016 per ton mile (Reference 13).

ANNEX XIII

WASTE DISPOSAL

1. Disposing of the waste or by-products which are created by reducing air pollution from burning fossil fuels will present serious problems.
2. A major part of this report is directed at reducing the amount of SO_x in the air. While it is possible to set up a plan (see Chapter III) to lower 1980 SO_x emissions to the 1960 level, the result will be 37,000,000 tons of SO_x per year or 16,600,000 long tons of sulfur not put into the air (see Tables 12 and 14). Of this reduction, 3,700,000 long tons of sulfur will be left in the ground in coal or left on the ground as tailings from the coal cleaning operations. 11,100,000 long tons will be scrubbed out of the flue gases and combined with limestone to produce gypsum and 3,000,000 long tons will be removed from heavy fuel oil and will be available for sale. The elemental sulfur market in the United States in 1980 is expected to be 14,000,000 to 15,000,000 long tons (Reference 36). Because other potential sources of sulfur, e.g., smelters and sour gas are expected to grow at a high rate, a cost estimate which assumes a substantial credit for sulfur sales seems unrealistic except in unusual circumstances.
3. The relative costs and the state of the art indicates that it is more likely the sulfur from oil will get to the market before sulfur from flue gas (References 30, 39). Thus it would appear that throw-away processes will be favored unless use of sludge removal or other economic factors to make them economically unreasonable.
4. The sludge containing fly ash, unreacted calcium carbonate, precipitated calcium sulfite and calcium sulfate, and a lot of water containing calcium nitrite and calcium nitrate in solution, must be disposed of. For scrubbing 570,000,000 tons per year of coal, sludge will be formed at the rate of 300,000,000 tons per year. (60 percent solids, 40 percent water.)
5. Scrubbing 25,000,000 tons of SO_x out of flue gases is calculated to scrub out an accompanying NO_x and to form 3,000,000 tons of calcium nitrite and calcium nitrate. The disposal of this very soluble salt is a major problem of some magnitude if it is to be kept out of streams, ponds and rivers.

6. Twenty-three million tons of refuse, trash, iron sulfides, and the like, would result from the preparation of 90,000,000 tons of deep cleaned coal. The techniques for handling the process water and rain-water runoff from such a quantity of waste cannot be overlooked.

7. Natural gas has been assumed to be a clean fuel. As it comes from the wells in the fields it contains varying quantities of hydrogen sulfide. This hydrogen sulfide must be removed, and disposed of, because of its toxicity. Historically, much of it has been burned to SO_x from small, lean sources. When sources were rich enough, the hydrogen sulfide was converted to sulfur for sale. By 1980, it must be assumed that all hydrogen sulfide is converted to sulfur if pollution abatement is to be a reality. The question arises, what are Canada and Venezuela to do with their sour gas? By 1980, Canada will produce 21,000,000 long tons of sulfur through their gas fields alone (Reference 36).

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APPENDIX I

THE U. S. STRATEGY AND SO_x ABATEMENT

THE U. S. STRATEGY AND SO_x ABATEMENT

The U. S. control strategy synthesized for the purpose of the O.E.C.D. study is presented on pages 15 and 18 of the U. S. National report. The 1980 situation is presented in Table 7 for the no control case and in Table 8 for the case where the stated strategy is employed. Comparison of the data in these tables for SO_x emissions show the desired reduction is accomplished by changes impressed on the practices in using heavy fuel oil and hard coal, with the great bulk in the reduction owing to the changer in the hard coal category.

The method used for arriving at the 1980 fuel requirements is described in Annex IV of the U. S. National report. During this phase of the report preparation, it was necessary to make certain assumptions concerning the availability of fuels to the respective sectors. Basically the large amount of coal is allocated to the electric power industry on the basis of the amount of kwh equivalents required to furnish the projected electricity needs not covered by other fuel sources. Because of the cost premium, natural gas and heavy fuel oil supplies were allocated to satisfy all other sector demands before power stations. It is felt that the large power station will have a cost advantage in applying fuel gas cleaning systems over paying a fuel premium.

SO_x Emissions Table*

	(1)		(2)		(3)	
	1970 Actual		1980		1980	
	Resid	Coal	No Control		Cont. 1970	
	Resid	Coal	Resid	Coal	Resid	Coal
Power Stations	2.40	14.69	5.50	31.75	1.85	20.96
Other Industry	0.87	6.68	1.04	7.99	0.35	2.07
Total for these						
Sectors		24.64		46.08		25.23
Grand Total		29.53		51.80		28.39

*SO_x emissions are expressed as millions of metric tons. (These data are from The U. S. National report: (1) Table 5, (2) Table 8, and (3) Table 9).

Although the data do not permit an exact calculation of all sulfur removed, those presented for the two sectors of power plants and other industry satisfy the large percentage of sulfur units.

Consumption of hard coal and heavy fuel oil (resid) for these sectors is given in Table 4 and 6 of the U. S. National report. These numbers yield the amounts of SO_x emissions given above when converted with the appropriate emission factors. Note that the resid assumed available is 2.6 percent sulfur and is desulfurized to 0.87 percent as per the stated strategy.

The tables in the U. S. National report give the fuel requirements and projected emissions for all fuels and source categories. The projected total SO_x emissions for the year 1980:

51.80 MMT without control
28.38 MMT with application of stated control strategy
23.42 MMT reduction in SO_x emissions required in 1980 to control
to 1970 level

Since the calculation of the total situation is very complex and the bulk of the SO_x emissions can be seen to occur from the combustion of hard coal in the public power sector, a detailed analysis of this combination of fuel and sector only will be presented for the sake of brevity.

The assumptions applied in the formulation of the strategy pertinent to using hard coal in public power stations led to the following structure:

- (a) Concentration of industrial activity supplied by coal is much more heavy in the eastern than western U. S. Therefore all demands for low sulfur coal will be supplied by natural low sulfur eastern coal or mechanically deep cleaned high sulfur eastern coal. Since cleaned coal provides about a 30 percent ash reduction, this portion will be allocated to industrial sectors.
- (b) The portion of natural low sulfur eastern coal not allocated to industry will be used in power stations.
- (c) All western coal is used in power stations.
- (d) The remaining power plant capacity is left with only high sulfur eastern coal. A sufficient capacity of this remainder is required to implement flue gas cleaning to accomplish the desired reduction; the remaining capacity is uncontrolled.

The total hard coal required to meet all energy demands in 1980 is
mst = million short tons 872.5 mst
(Table 6, page 16). Of this amount, power stations require. . . . 682.0 mst

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The strategy calls for implementation of steps to accomplish the desired reduction of sulfur emissions for hard coal burning by applying technology which is judged most feasible within the time constraints and degree of development.

Use low sulfur western coal (1 percent sulfur) to account for 10 percent of the total coal demand and allocate to power plants	87.3 mst
Use natural low sulfur eastern coal (0.7 percent sulfur) to account for 18 percent of the total coal demand	157.0 mst
Deep clean 15 percent of the high sulfur eastern coal to 0.7 percent sulfur, reduce ash, and allocate to all sectors other than power plants (equals 13.5 percent or approximately 14 percent of all coal)	118.0 mst
Total low sulfur coal available to all sectors other than power plants	275.0 mst
Total low sulfur coal required by all sectors other than power plants	190.5 mst
Low sulfur coal available to power stations from natural low sulfur eastern coal	84.5 mst
Total low sulfur coal available to power stations from both eastern and western sources	171.8 mst
Total high sulfur coal required to furnish balance of demand for power stations	510.2 mst
Employ flue gas scrubbing on 127.7 mtons capacity of 2.7 percent sulfur coal reducing by 90 percent	127.7 mst
Remainder of high sulfur coal capacity not controlled	382.5 mst

The sulfur oxide emission situation after control in 1980 is then:

Power Plant

From low sulfur eastern coal	
84.5 x 38 x 0.7 x 1/2000	= 1.13 mst SO _x
From low sulfur western coal	
87.3 x 38 x 1.0 x 1/2000	= 1.66 mst SO _x

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From flue gas cleaning	
$127.7 \times 38 \times 0.1 \times 2.7 \times 1/2000$	$= 0.66 \text{ mst SO}_x$
From high sulfur eastern coal	
$382.5 \times 38 \times 2.7 \times 1/2000$	$= \frac{19.65}{23.10} \text{ mst SO}_x$
	23.10 mst SO_x
Total	$= 20.96 \text{ MMT SO}_x$

The total required reduction in all sectors is 23.4 MMT to control the 1980 situation to the 1970 level (actually this is better than the 1970 case as estimated). This value of 20.96 MMT of SO_x emissions is that presented in Table 8 of the U. S. National report. Similar calculations for all other fuel - sector combinations have been performed to give the figures presented in the U. S. National report, which show that the control of potential 1980 emission to the 1970 levels are possible with the stated strategy.

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APPENDIX II
COSTS FOR OIL DESULFURIZATION

COSTS FOR OIL DESULFURIZATION

In regard to the cost of residual desulfurization, I have examined several references for information on various RDS processes. From this data, I have developed the table below.

<u>PROCESS</u>	<u>SIZE BPSD</u>	<u>INVESTMENT \$ MILLIONS</u>	<u>\$ PER BPSD</u>
CHEVRON RDS - ISOMAX	50,000	16.7	335
SCALED TO 0.6 POWER FOR U. S. REPORT	31,500	12.6	400
ESSO RESID FINING	--	--	200-500
HYDROCARBON RESEARCH H-OIL	40,000	8.4	210
IFP	50,000	13.1	262
UOP RCD - ISOMAX	40,000	9.7	243
GULF HDS	35,000	15.0	429

As can best be determined from the various references (copies appended here), these costs account only for these RDS units - the reactor, separators, and product distillation. No costs are included for the required increase in the capacities of the hydrogen, sulfur and H₂S plant or ancillary equipment.

Recalculating the costs for the U. S. case using these figures and the assumptions behind them may show greater agreement with those cost figures presented by other national reports.

From the U. S. National report, Annex X, we have the investment costs for desulfurization of:

	<u>REPORT</u>	<u>BASE SITE</u>
RDS - ISOMAX 31,500 BPSD	10.8	10.8
PRODUCT DISTILLATION	1.8	1.8
HYDROGEN PLANT	5.3	
H ₂ S & SULFUR PLANT	4.6	
	<u>22.5</u>	<u>12.6</u>
OFFSITE	24.3	
CONTINGENCY	4.7	
TOTAL INVESTMENT	<u>51.5</u>	
		\$400 bpsd

Then applying the following figures for the total residual oil desulfurization capacity,

1173×10^6 bbl/yr. required of oil

.88 load factor

1335×10^6 bbl/yr. capacity for desulfurization

3.67×10^6 bpsd total capacity

cost range is \$200-\$500/bpsd for plants from 30K to 50K

Minimum cost = $\$200 \times 3.67 \times 10^6 = \$7.34 \times 10^8$

Maximum cost = $\$500 \times 3.67 \times 10^6 = \$18.35 \times 10^8$

These figures represent only the base minimal investment then for the RDS operation - they do not include the provisions for increased capacities of the hydrogen plant, H₂S and sulfur plants, and other ancillaries nor factors for off-site investment or contingency.

The O.E.C.D. draft consolidated report given capital costs for resid desulfurization on page 22 (bis) table 11 ranging from \$380 to \$500 per annual ton of sulfur removal capacity for the U. K. and the Netherlands. This figure for the U. S. case, if recalculated on the basis of the foregoing discussion, is obtained - \$200 to \$500 range. This range is calculated as follows:

Assume the average sulfur content of the resid fuel is at 2.7 percent sulfur and the resid is desulfurized to a level of 0.87 percent sulfur.

1980 resid demand 1173×10^6 bbl/yr.

1173×10^6 bbl/yr. $\times 42$ gal/bbl $\times 7.92$ lb/gal $\times$ ton/2000 lbs =
 195×10^6 tons resid/yr.

5.3 mst at 2.7 percent sulfur

1.7 mst at 0.87 percent sulfur

Therefore 3.6 million short tons of sulfur are removed from the resid oil. For the capital cost range previously calculated, i.e., minimum cost = $\$7.34 \times 10^8$ and maximum cost = $\$18.35 \times 10^8$, we have as range of from \$200 to \$510 per ton of sulfur removal capacity.

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I would like to call to your attention, then, that a comparison of these cost figures to those presented in the U. S. National report for desulfurization are very much the same when adjusted to this basis, i.e., the desulfurization unit, the separator and product distillation unit, without off-site investment and contingency factors.

Certainly differences arise concerning the inclusion of costs for components such as the hydrogen and H₂S - sulfur plants which are utilized also by other of the refinery operations. While it is not legitimate to assign the whole of these costs to the operations involved to remove sulfur from fuels to achieve control of sulfur oxides, it is likely that a considerable investment in such components will be necessary if the required quantities of desulfurized resid are to be made available.

The questions which now arise are: What basis is assumed by each national report in the calculation of the oil desulfurization costs; what basis should be used?

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APPENDIX III
ELECTROSTATIC PRECIPITATOR COSTS

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ELECTROSTATIC PRECIPITATOR COSTS

The following discussion covers the subject of electrostatic precipitators (ESP) and provides the modified estimates as requested.

From the Southern Research Institute report (copies attached as Annex IV), we have data which indicate a total installed 1970 ESP capacity for 358×10^6 acfm of flue gases from coal combustion. Based on the conversion factor of 2.0 cfm of flue gas per ton of coal fired per year (for a 0.55 load factor), we estimate the total ESP power station capacity requirement for 1980 to be:

$$554 \text{ mst} \times 2.0 = 1108 \times 10^6 \text{ acfm}$$

The ESP capacity required to be added between 1968 and 1980 is then the difference, i.e.,

$$1108 \times 10^6 - 358 \times 10^6$$

or 750×10^6 acfm additional capacity

If we want to include replacement of all units over 30 years old by 1980 (i.e., units having a design efficiency of less than 95 percent) we must account for an additional 78.5×10^6 acfm capacity, bringing the new capacity figure to:

$$838 \times 10^6 \text{ acfm}$$

We then must furnish ESP capacity to handle 838×10^6 acfm or for a capacity of 419×10^6 tons per year of coal for public power stations.

ESP HISTORY STATUS

<u>Year</u>	<u>1950</u>	<u>1968</u>	<u>1980</u>	
Coal burned	91.8	298	554	(power stations)
(mst)			191	(other sectors)
Total gas volume	184	596	1108	
10^6 acfm				
Volume equipped				
with ESP	78.5	358	1108	
10^6 acfm				

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The trend data for conversion efficiency shows that about 0.87 lbs of coal are required for each kilowatt-hour. Applying this factor and a load factor of 0.55, a total capacity of 2.2×10^8 KW is calculated. At the cost basis of \$5.00/KW installed, we then have a total cost of 1.1×10^9 for power plants.

The situation is more difficult for costing the industrial units because we lack detailed data of the nature on-hand for power plants. We have chosen to apply the cost for ESP units for power plants on the gas handling basis.

For 191×10^6 tons/yr. of coal fired and a 0.8 load factor, it is estimated that a total volume rate of 2.9×10^8 acfm of gas is to be cleaned. Further take the unit size to be 10^5 acfm with a resultant unit cost (from figures in attachment) of \$90,000. This analysis yields a total cost of \$257,000,000.

The total costs for all electrostatic precipitator capacity is then estimated at \$1.36 Billion (i.e., $\$1.36 \times 10^9$) for the U. S. case - a figure not in significant disagreement with that in the U. S. National report.

Table 15.5

Fly Ash Precipitator Installations

Pptr Contract Year	(1)		Five (5) Yr Periods		Avg Vol/Yr During Period 10 ⁶ acfm	Pptr Operation Year	Accumul Gas Vol With Pptrs 10 ⁶ acfm	Coal Burned 10 ⁶ tons per year	(2) Total Gas Vol Calculated From Coal Burned 10 ⁶ acfm	Percent of Total Vol with Pptrs
	No. of Installations	Total Gas Vol Millions acfm	No. of Installations	Total Gas Vol 10 ⁶ acfm						
1923	1	0.80				1925	0.80	35.6	53.4	1.5
1926	2	1.35	3			1928	2.15	38.0	58	3.7
1927	2	3.59	11	8.58	1.72	1929	5.74	41.8	62.8	9.1
1928	1	0.22	2			1930	5.98	40.3	60.5	9.9
1929	4	2.62	26			1931	8.58	36.1	54.2	15.8
1930	6	1.43	10			1932	10.01	38.0	42.0	23.8
1931	2	0.46	3			1933	10.47	38.5	42.8	24.5
1932	1	0.37	2	3.46	0.69	1934	10.84	31.4	47.0	23.1
1933	2	0.68	4			1935	11.52	32.7	49.0	23.5
1934	2	0.52	4			1936	12.04	40.1	60.0	20.1
1935	2	0.79	5			1937	12.83	42.9	64.5	19.9
1936	13	3.59	23			1938	16.42	36.4	57.6	23.5
1937	15	4.71	29	12.68	2.54	1939	21.13	44.5	66.8	31.6
1938	1	0.25	1			1940	21.38	51.5	77.3	27.7
1939	8	3.34	17			1941	24.72	62.6	94.0	26.3
1940	22	5.42	36			1942	30.14	66.2	99.3	30.4
1941	31	7.84	52	30.38	4.06	1943	37.98	77.3	116.0	32.7
1942	9	3.37	29			1944	41.35	80.1	120.0	34.5
1943	1	0.96	1			1945	42.31	74.7	112.0	37.8
1944	8	2.69	11			1946	45.00	72.2	134.0	41.6
1945	13	2.78	17			1947	47.78	89.5	154.0	35.7
1946	22	6.12	39			1948	53.90	99.6	149.5	36.1
1947	28	9.37	59	36.87	7.37	1949	60.57	83.9	128.0	52.8
1948	23	9.97	40			1950	76.54	91.8	138.0	55.5
1949	20	5.33	25			1951	81.87	105.7	159.0	51.5
1950	19	6.06	35			1952	88.75	107.1	161.0	55.1
1951	26	14.12	61			1953	102.87	115.9	174.2	59.1
1952	19	7.60	25	42.35	8.47	1954	110.47	118.4	178.0	62.1
1953	23	9.27	37			1955	119.74	143.8	216	55.4
1954	9	4.48	15			1956	124.22	158	237.5	52.3
1955	23	14.04	36			1957	138.26	162	344	56.7
1956	32	26.57	37			1958	164.63	-	-	-
1957	26	17.40	43	80.97	16.19	1959	182.23	-	-	-
1958	13	7.53	19			1960	189.78	176.2	265	71.6
1959	23	5.41	37			1961	205.19	-	-	-
1960	17	11.00	26			1962	216.28	-	-	-
1961	12	7.56	16			1963	223.84	211	317	70.6
1962	16	17.07	28			1964	240.91	-	-	-
1963	15	12.54	21	68.10	13.62	1965	253.45	244.8	368	68.9
1964	16	19.84	27			1966	273.29	258.5	401	68.2
1965	33	27.17	49			1967	300.46	374.0	412	72.9
1966	48	97.34	80			1968	337.70	-	-	-
1967	55	72.51	117	257.61	51.53	1969	430.21	-	-	-
1968	46	58.76	106			1970	438.97	-	-	-
1969	40	42.93	67			1971	531.90	-	-	-
Grand Totals	741	531.9	1331							
				741						

(1) Includes all fly ash precipitators except rebuilds.

(2) Based on an 85% load factor.